TECHNICAL REVIEW AND EVALUATION
WELLTON MOHAWK GENERATING FACILITY
AIR QUALITY PERMIT NUMBER 1001653

I. INTRODUCTION

This Class I operating and installation permit is issued to Dome Valley Energy Partners, LLC, the Permittee, for the construction and operation of the proposed Wellton Mohawk Generating Facility (WMGF). The WMGF is a natural-gas fired, combined cycle power generating plant, which will be located at the intersection of Avenue 22 and Street 11 in Wellton, Yuma County, Arizona.

A. Company Information

Facility Name:	Wellton Mohawk Generating Facility
Mailing Address:	Dome Valley Energy Partners, LLC 550 Mamaroneck Ave, Suite 303 Harrison, NY 10528
Facility Location	10800 South Ave 22E Wellton, Yuma County, Arizona 85356

B. Attainment Classification

The proposed source is to be located in an area that is designated as attainment or unclassified for all the following criteria pollutants: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter less than 10 microns in diameter (PM_{10}) and sulfur dioxide (SO_2).

II. PROCESS DESCRIPTION

The WMGF is a natural gas-fired, combined cycle base-load plant that will be permitted to have the option of using either General Electric (GE) 7FA combustion turbine generators (CTG) or Siemens-Westinghouse (SW) CTGs. The facility will have a total nominal power rating of 620 megawatts (MW) with the GE7FA CTGs or 640 MW with the SW501F CTGs. The power block will be installed in a two-on-two configuration, which will comprise two CTGs, two heat recovery steam generators (HRSG) with supplemental duct firing and two steam turbine generators (STG). Each of the two turbines in the GE power block is rated at 170 MW while each in the SW power block is rated at 180 MW. The steam turbine and the duct burners associated with the steam cycle can generate a maximum of 140 MW of power.

The support processes associated with each turbine will consist of the following equipment:

1. One 170,000 gallons per minute, 6-cell, wet, mechanical-draft cooling tower equipped with high efficiency drift eliminators;
2. One auxiliary boiler equipped with low-NO_x burners and a maximum natural gas fuel burn rate of 38 million British Thermal Units per hour (MMBtu/hr);
3. Two natural gas-fueled black start generators, each rated at 6 MW;
4. One diesel-fueled fire pump rated at 303 horsepower (hp);
5. Main transformers; and
6. Other ancillary equipment.

A process flow diagram of the WMGF project is presented in Figure 1. This project is unique in that, in addition to using conventional inlet chilling techniques such as foggers or evaporative coolers, SEECOT™ Solar Thermal Technology will be employed[1], which is used to increase the output and efficiency of the CTGs. The combustion turbine compresses the chilled air from the SEECOT™ system, which is then mixed with natural gas and burned in the dry low-NO_x (DLN) combustors. The resulting high temperature gases pass through the power turbine and exhaust to the HRSGs. The power turbine drives both the compressor and an electrical generator. The turbine exhaust gases are treated with a Selective Catalytic Reduction (SCR) system and an oxidation catalyst to further control NO_x, CO, and volatile organic compound (VOC) emissions before being exhausted to the atmosphere.

The HRSGs are boilers that generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental duct firing of the HRSGs using natural gas may be performed so that additional steam can be produced for the STG. As a result, the HRSGs will generate additional emissions due to the firing of the duct burners. The STG is capable of generating 140 MW. Because the STG does not combust fuel, there are no air emissions from this unit.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system that rejects waste heat to the atmosphere by evaporation in the cooling towers. Particulate matter that is entrained in the water vapor escaping from the cooling towers is controlled by high efficiency drift eliminators.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation.

III. EMISSIONS

Tables 1 through 4 present the proposed short-term and annual emission limits for the units. The proposed permit limits are based on vendor and applicant data, and the application of control devices selected through the Best Available Control Technology (BACT) analysis.

A. Normal Operations - Hourly Emission Rates

Figure 1. Process Flow Diagram

[1] The SEECOT™ system (inlet air-cooling) uses parabolic troughs located along a North-South axis to trace the movement of the sun and to convert solar radiation into thermal energy. A benign fluid is employed as the heat transfer medium. This heat transfer fluid can be heated to temperatures ranging from 500 to 550 ºF. This thermal energy produces low-pressure steam (approximately 125 pounds per square inch gauge (psig) saturated steam), which, in turn, powers a two-stage absorption chiller that is used to cool the CTG inlet air temperature. A CTG is a constant volume device, therefore, by cooling the inlet combustion air, the mass flow through the CTG can be increased, thereby increasing both the CTG electric output and efficiency. For example, if the CTG inlet air temperature is lowered to 45ºF, the amount of power generated can be increased approximately 12 percent dependent upon ambient air temperature.

Table 1 lists the combined cycle unit maximum hourly emission rates under normal operation at any combination of load and at ambient temperature, and includes emissions from duct firing. These maximum rates occur at 100% load with duct firing at 17 degrees Fahrenheit (^{0}F). Normal operations are defined as loads above or equal to 65% of the nameplate capacity.

Table 1. Hourly Emission Limits During Periods Other than Start-up or Shutdown

Equipment	Hourly Emissions, Each CTG and HRSG, lb/hr				
	NO_x[1]	CO[2]	VOC[3]	PM_{10}[4]	SO_2[5]
GE7FA	16.0	14.6	8.4	29.8	4.7
SW501F	18.3	16.7	9.5	33.1	5.3

1. Calculated from the 2.0 parts per million volume dry (ppmvd) NOx BACT limit and the maximum dry exhaust flow rate corrected to 15% oxygen (O_2).
2. Calculated from the 3.0 ppmvd CO BACT limit and the maximum dry exhaust flow rate corrected to 15% O_2.
3. Calculated from the 3.0 ppmvd VOC BACT limit and the maximum dry exhaust flow rate corrected to 15% O_2.
4. Calculated from PM_{10} content of 10 milligrams per cubic meter (mg/m^3) in pipeline quality natural gas.
5. Calculated from fuel sulfur concentration of 0.75 grains per dry standard cubic foot (gr/dscf).

Notes:
A. All emissions calculated at 100% load with duct firing at 17^0 F inlet temperature.
B. Each of the two duct burners is limited to 346 MMBtu/hr fuel rate for the GE7FA.
C. Each of the two duct burners is limited to 383 MMBtu/hr fuel rate for the SW501F.

B. Start-up and Shutdown Operations - Hourly Emission Rates

Start-up and shutdown operations are defined as loads below 65% of the nameplate capacity. Emissions of NO_x, CO, and VOCs from the combustion turbines during start-up and shutdown are significantly higher than during steady-state, full load operation. This is because combustion temperatures and pressures are rapidly changing during this procedure, which results in less efficient combustion and higher emissions, and because the DLN combustors are operating in diffusion mode, not DLN mode. In addition, pollution control systems such as oxidation catalysts are not as effective during the transitory temperature changes that occur during start-up and shutdown.

The NO_x, CO, and VOC start-up and shutdown emission rates, which are higher than emissions during normal operations, must be included in the annual potential to emit (PTE) calculations and be considered in the air quality modeling analyses. The only pollutant that requires a separate start-up and shutdown short-term modeling analysis is CO, because it is the only one of these three pollutants with short-term 1-hour and 8-hour air quality standards. For NO_x, the air quality standard is an annual standard. Therefore, the annual

NO_x emission rate that is modeled must include total emissions from both normal operations and start-up and shutdown operations. Because of the CO and NO_x modeling requirements to demonstrate compliance with air quality standards and increments, separate start-up and shutdown emission limits have been established for CO and NO_x and are listed in Table 2 for both the turbines. Compliance with the start-up and shutdown CO and NO_x emission limits in Table 2 shall be determined using continuous emissions monitoring systems (CEMS).

Table 2. Hourly Emission Limits During Periods of Start-up or Shutdown for Both Turbines

Equipment	Hourly Emissions, Each CTG and HRSG, lb/hr	
	NO_x[1]	CO[2]
GE7FA	166.7	1198.0
SW501F	166.7	1198.0

1. Although worst case 1-hour emissions will occur during a cold start, when the CTG is started after being shutdown for more than 48 hours, this rate was assumed for all starts.
2. Worst case 1-hour emissions will occur when the CTG is shutdown for 30 minutes and then followed by a hot start.

Even though VOC emissions are higher during start-up and shutdown operations, which are included in the annual VOC emission calculations, it is not practical to establish VOC start-up and shutdown emission limits for modeling purposes because of the difficulty in testing for compliance. Environmental Protection Agency (EPA) Reference Methods 25A and 18 stack tests are used for VOCs, which are very difficult to conduct during the non-steady-state conditions of startup and shutdown. In addition, a start-up and shutdown modeling analysis is not required for VOCs because there are no air quality standards for VOC and the relationship between hourly VOC emission rates and ambient ozone concentrations is unreliable. Therefore, separate VOC start-up and shutdown emission limits have not been established.

Because emissions of particulate matter (PM) or PM_{10} and emissions of SO_2 do not increase during start-up and shutdown, separate start-up and shutdown emission limits are not established for these pollutants.

C. Annual Allowable Emission Limits

Table 3 presents the maximum annual facility PTE considering all permitted sources. Annual operations will be limited by operational and hourly limits for normal, duct firing, start-up and shutdown operating modes. The total allowable emissions in Table 3 include emissions from the auxiliary boiler, which will be limited to 480 hours of operation per year and the black start generators and fire pump engine, which will each be limited to 200 hours of operation per year. Emissions from the cooling tower are also included for the PM_{10} PTE.

The PTE numbers shown in Table 3 for the CTGs were calculated at 100% load conditions with duct firing at 17 ^{0}F and by assuming 20 cold starts, 100 warm starts and 200 hot starts. The maximum duct firing rates of 346 million British Thermal Units per hour (MMBtu/hr) for the GE7FA CTGs and 383 MMBtu/hr for the SW501F CTGs were included at this load to develop worst case emissions estimates. The amount of time a unit has been shutdown will determine whether the subsequent start-up is hot, warm, or cold.

According to information from the turbine manufacturer, a hot start-up occurs if a unit has been offline for less than 8 hours, a warm start-up if it has been offline between 8 and 48 hours, and a cold start-up if it has been offline for greater than 48 hours. Emissions per start-up and shutdown event, as shown in Table 2, were provided by the turbine manufacturer. Based on the durations of the various start-ups and shutdowns provided, normal emissions at the rates shown in Table 1 were calculated to occur for 5,565 hours annually, while start-up and shutdown emissions at the rates shown in Table 2 were calculated to occur for 1,435 hours. The downtime, when no emissions occur, was calculated to be 1,760 hours.

Table 3a. Average Annual Emissions for the GE7FA CTG

Equipment	Average Annual Emissions, Tons Per Year (TPY)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle System 1	162.4	379.6	125.6	130.5	20.6
Combined Cycle System 2	162.4	379.6	125.6	130.5	20.6
Cooling Tower	N/A	N/A	N/A	13.0	N/A
Auxiliary Boiler[1]	2.5	0.7	0.0	0.0	0.0
Black Start Generator 1[2]	2.0	4.0	0.6	0.5	0.0
Black Start Generator 2[2]	2.0	4.0	0.6	0.5	0.0
Fire Pump[2]	0.7	0.1	0.1	0.0	0.0
TOTAL	332.0	768.0	252.5	275.0	41.2

1. Limited to 480 hours/year.
2. Limited to 200 hours/year.

Note:
A. N/A = Not Available
B. NO_x emissions will be controlled using low-NOx burners and SCR.
C. CO and VOC emissions will be controlled using an oxidation catalyst.

Table 3b. Average Annual Emissions for the SW501F CTG

Equipment	Average Annual Emissions, TPY				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle System 1	168.7	386.1	129.3	144.7	23.4
Combined Cycle System 2	168.7	386.1	129.3	144.7	23.4
Cooling Tower	N/A	N/A	N/A	13.0	N/A
Auxiliary Boiler[1]	2.5	0.7	0.0	0.0	0.0
Black Start Generator 1[2]	2.0	4.0	0.6	0.5	0.0
Black Start Generator 2[2]	2.0	4.0	0.6	0.5	0.0
Fire Pump[2]	0.7	0.1	0.1	0.0	0.0
TOTAL	344.6	781.0	259.9	303.4	46.8

1.	Limited to 480 hours/year.
2.	Limited to 200 hours/year.
Note:	
A.	N/A = Not Available
B.	NO_x emissions will be controlled using low-NO_x burners and SCR.
C.	CO and VOC emissions will be controlled using an oxidation catalyst.

D. BACT and New Source Performance Standard (NSPS) Emission Limits

Additional emission limits or concentrations required by regulations (e.g., NSPS, BACT) are shown in Table 4 on the following page. No alternate operating scenarios have been proposed by the applicant.

IV. APPLICABLE REGULATIONS

There are two components to the New Source Review (NSR) permitting program codified in Article 4 of the Arizona Administrative Code: Prevention of Significant Deterioration (PSD) and Non-Attainment NSR. The PSD program is applicable in areas that are attaining air quality standards (or are "unclassified"), and it is intended to prevent further deterioration of air quality in the area. Non-attainment NSR applies in areas that are exceeding air quality standards.

In order to trigger the applicability of either of these programs, the source must meet the definition of a major stationary source. As shown in Table 5, the WMGF is a major source because it is a "categorical source", as defined in A.A.C. R18-2-401 with potential emissions of a regulated pollutant above the 100 tons per year (TPY) threshold. Because the proposed location is designated attainment/unclassified for all criteria pollutants, only applicability with the PSD permitting program must be evaluated. The PSD applicability significant emission rate thresholds are exceeded for NO_x, CO, SO_2, VOCs, and PM_{10}.

The PSD permitting program requirements are contained in A.A.C. R18-2-406 of the ADEQ regulations. The requirements include an analysis of BACT; an ambient air quality impacts analysis for increment consumption and National Ambient Air Quality Standards (NAAQS); a visibility and other air quality related values (AQRV) impact analysis for Class I wilderness areas; and an analysis of additional impacts, including growth, soils, vegetation, and visibility impairment.

A. Permitting Requirements

As described above, the proposed facility is a major source for NO_x, CO, SO_2, VOCs, and PM_{10} under the PSD permitting program. The source is also a major source under A.A.C. R18-2-302 of the ADEQ regulations, which implement the Title V permitting requirements. ADEQ has a unitary permit program so that sources apply for a permit under NSR and Title V concurrently. The permit application submitted by the source covers both the PSD and Title V programs.

Table 4. Additional BACT and NSPS Emission Limits

Equipment	Concentration or Rate Limits

	NO_x	CO	VOC	PM_{10}	SO_2
Each Combustion Turbine Exhaust Operating in Conditions Other than Start-up	Determined by calculation[1]	--	--	--	SO_2 emissions <150 ppmvd or sulfur fuel content of <0.8% by weight[2]
Each Duct Burner Exhaust	0.2 lb/MMBtu[3] and 1.6 lb/MW-hr	--	--	0.03[4] lb/MMBtu	0.02[5] lb/MMBtu
Each Combined Cycle System Exhaust	2.0 ppmvd, 3-hour rolling average (subject to 18-month demonstration period)	3.0 ppmvd 3-hour rolling average	3.0 ppmvd 3-hour rolling average	0.0264 lb/MMBtu for both turbines, 3-hour rolling average	0.0023 lb/MMBtu for both turbines, 3-hour rolling average

[1] Based on NSPS Subpart GG, 40 Code of Federal Regulations (CFR) 60.332(a)(1).
[2] Based on NSPS Subpart GG, 40 CFR 60.333(a).
[3] Based on NSPS Subpart Da, 40 CFR 60.44a(a) and 60.44a(d)(1).
[4] Based on NSPS Subpart Da, 40 CFR 60.42a(a)(1).
[5] Based on NSPS Subpart Da, 40 CFR 60.43a(b)(2).

"--" means that no additional concentration or rate limit is specified for that pollutant.

Notes:

A. Concentration limits are parts per million by volume dry (ppmvd) corrected to 15% oxygen on a dry basis.

B. The 2.0 ppmvd limit for NO_x is a 3-hour rolling average calculated from continuous monitors. This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first 18-months of operation based on the NO_x demonstration required by the permit.

C. Emission limits for CO are 3-hour rolling averages calculated from continuous monitors. VOC, SO_2 and PM_{10} averaging times are consistent with the stack testing methods (three 1-hour averages).

D. Ammonia emissions associated with the SCR control system will be limited to 10.0 ppmvd on a 24-hour rolling average. This limit maybe reduced to 7.5 ppmvd on a 24-hour rolling average after the 18-month demonstration period.

E. To monitor for compliance with 40 CFR Part 60 Subpart GG, NO_x emissions shall be calculated as required by 40 CFR 60.335(c)(1) unless the CTGs are installed with a controller programmed with an algorithm acceptable to the Director and Administrator that continuously corrects for variations in ambient humidity, temperature, and pressure yielding a relatively constant NO_x concentration when corrected to 15 percent oxygen, in which case the continuous emission monitoring data can be used without the 40 CFR 60.335(c)(1) correction.

F. When multiple or alternative limits apply, the most stringent limit governs.

Table 5a. Potential to Emit for the GE7FA CTG and Applicability Thresholds

Pollutant	Potential Emissions TPY	Major Source Threshold TPY	Significance Level for BACT TPY	BACT Applicable?
NO_x	332.0	100	40	Yes
CO	768.0	100	100	Yes
VOC	252.5	100	40	Yes
PM_{10}	275.0	100	15	Yes
SO_2	41.2	100	40	Yes

Table 5b. Potential to Emit for the SW501F CTG and Applicability Thresholds

Pollutant	Potential Emissions TPY	Major Source Threshold TPY	Significance Level for BACT TPY	BACT Applicable?
NO_x	344.6	100	40	Yes
CO	781.0	100	100	Yes
VOC	259.9	100	40	Yes
PM_{10}	303.4	100	15	Yes
SO_2	46.8	100	40	Yes

1. *Title V*

As a major source for Title V, the proposed facility is required to obtain a Class I (Title V) permit. The permit application and its supplements submitted by the source list applicable requirements and contain compliance information, as well as a certification of compliance, which are all required as part of a Title V permit application. Title V includes the specification of appropriate monitoring requirements and, as outlined in Section VI of this document, monitoring provisions are included in the permit.

2. *PSD*

As shown in Tables 5a and 5b above, the facility will have potential emissions above the PSD significance thresholds for NO_x, CO, VOC, SO_2 and PM_{10}. As a PSD major source, the facility is required by A.A.C. R18-2-406 to obtain a PSD permit. As explained in this Section, the PSD requirements codified at A.A.C. R18-2-406 are applicable for these pollutants. The requirements include a determination of BACT for NO_x, CO, VOC, SO_2 and PM_{10}, an analysis of the air quality impact of the project, and additional impacts, which are discussed in Sections V and VII respectively.

B. Other Applicable Requirements

1. *New Source Performance Standards (NSPS)*

Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to ADEQ, and Article 9 of the ADEQ regulations adopted the NSPS by reference. For the proposed project, the combustion turbines are subject to NSPS Subpart GG, the duct burners at the heat recovery steam generators are subject to Subpart Da, and the Auxiliary Boiler is subject to Subpart Dc.

(a) NSPS Subpart GG, *Stationary Gas Turbines*, is applicable to turbines with heat input capacities greater than 10 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart GG for the proposed turbines:

(1) §60.332, Standard for NO_x, includes an equation to calculate allowable NO_x emissions in ppmvd. From the equation, the nominal NO_x emission rate for the proposed turbines is 75 ppmvd @ 15% O_2 (without correction for thermal efficiency), which is less stringent than the permitted rate.
(2) §60.333, Standard for SO_2, specifies SO_2 emissions <150 ppmvd or a sulfur fuel content of <0.8% by weight. Natural gas is the only fuel that will be combusted in the CTGs and is inherently low in sulfur. Compliance with this standard will be met by burning only pipeline quality natural gas.
(3) §60.334, Monitoring of Operations, requires monitoring of sulfur and nitrogen content of the fuel being fired in the turbine on a daily basis. A custom schedule for determination of these values may be developed based on the design and operation of the turbines and the characteristics of the fuel supply. The custom schedule shall be substantiated with data and must be approved by the Director before it can be used to comply with §60.334(b).
(4) §60.335, Test Methods and Procedures, specifies the methods to determine the nitrogen and sulfur contents of the fuel, and how to determine compliance with the NO_x and SO_2 standards. Appropriate test methods are also discussed.

Because the BACT requirements for this permit will mandate much lower emissions rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

(b) NSPS Subpart Da, *Electric Utility Steam Generating Units*, is applicable to duct burners at heat recovery steam generators with heat input capacities greater than 250 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Da for the proposed duct burners:

(1) §60.42a(a)(1), Standard for PM, specifies that PM not exceed 0.03 pound per million British Thermal Units (lb/MMBtu) heat input. §60.42a(b) requires opacity to be $\leq$ 20% (6-minute average), except for one 6-minute period per hour not exceeding 27%.
(2) §60.43a(b)(2), Standard for SO_2, specifies that SO_2 not exceed 0.20 lb/MMBtu.
(3) §60.44a(a)(1), Standard for NO_x, specifies that NO_x (expressed as NO_2) not exceed 0.20 lb/MMBtu heat input, based on a 30-day rolling average. For a new source, §60.44a(d)(1) specifies that NO_x (expressed as NO_2) not exceed 1.6 pounds per megawatt-hour

(lb/MW-hr) gross energy output, based on a 30-day rolling average. Compliance provisions for duct burners subject to §60.44a(a)(1) and §60.44a(d)(1) are specified in §§60.46a(j) and (k).

(4) §60.46a(c), Compliance Provisions, states that these standards apply at all times except start-up, shutdown, and malfunction.

(5) §§60.47a(a) and (b), Emission Monitoring, states a continuous monitoring system (CMS) is not required for opacity or SO_2 if gaseous fuel is the only fuel combusted. As per §60.47a(o), duct burners subject to §§60.44a(a)(1) or (d)(1) do not require the installation of CMS for NO_x; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; or a continuous flow monitoring system.

(6) §§60.48a(b), (c), and (d), Compliance Determination Procedures and Methods, specify the methods to determine compliance for PM, SO_2, and NO_x. Alternative methods are provided in §60.48a(e).

(7) §60.49a(a), Reporting Requirements, requires submittal of initial performance test data for SO_2, NO_x, and PM.

(8) §60.49a(b), Reporting Requirements, specifies the submittal of the information listed for SO_2 and NO_x.

(9) §60.49a(g), Reporting Requirements, requires the submittal of a signed statement regarding the items listed.

(10) §60.49a(h), Reporting Requirements, defines excess emissions for opacity and requires quarterly reporting.

(11) §60.49a(i), Reporting Requirements, requires submittal of semiannual reports.

(12) §60.49a(j), Reporting Requirements, states that a source may submit electronic reports in lieu of the written reports required under paragraphs (b) and (h).

Because the BACT requirements for this permit will mandate much lower emissions rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

(c) NSPS Subpart Dc, *Small Industrial-Commercial-Institutional Steam Generating Units*, is applicable to boilers with heat input capacities between 10 and 100 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Dc for the proposed auxiliary boiler:

(1) Note that the SO_2 and PM emission requirements in Subpart Dc only apply to sources combusting coal, oil, or wood. Also, there are no requirements in Subpart Dc for NO_x.

(2) §60.48c(a), Reporting and Recordkeeping Requirements, requires the submittal of the notification of the date of construction, anticipated date of start-up, and date of actual start-up.

(3) §60.48c(g), Reporting and Recordkeeping Requirements, requires the submittal of the amounts of fuel combusted each day.

(4) §60.48c(j), Reporting and Recordkeeping Requirements, specifies the reporting period as 6 months.

Because the BACT requirements for this permit will mandate much lower emission rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

2. Accidental Release of Ammonia

Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance on-site at a facility to its threshold quantity. The source has proposed using ammonia in the SCR NO_x control system. At the time the application was submitted, the design specifications for the SCR system was not complete, thus, the type, concentration, and quantity to be stored on-site are not known. If more than a threshold quantity (20,000 pounds of aqueous ammonia or 10,000 pounds of anhydrous ammonia) will be stored on-site, this will trigger risk management planning requirements. A Risk Management Plan is required by the date on which a regulated substance is first present above the threshold quantity. Consequently, a Risk Management Plan for the storage and use of ammonia will be required before ammonia in excess of the threshold can be stored on-site.

In addition to a Risk Management Plan, under Section 112(r)(1) of the Clean Air Act, the source also has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

3. Acid Rain

The combined cycle units are considered Stage II affected units under the Title IV Acid Rain Program and an Acid Rain permit must be obtained prior to operation. As part of a supplement to its permit application, the source submitted an Acid Rain permit application. The proposed permit serves as a combined PSD, Title IV, and Title V permit. The permitted emission limits, monitoring, recordkeeping, and reporting requirements of the proposed permit incorporate the applicable Acid Rain provisions of 40 CFR Parts 72, 73, and 75.

Because the facility is not yet constructed, the source does not hold SO_2 allowances and will have to obtain such allowances to sufficiently cover its previous year's emissions as of the allowance transfer deadline. Emission limits for NO_x are not applicable to the project because the Acid Rain provisions only apply to coal-fired units. Monitoring requirements from 40 CFR Part 75 are discussed in Section VI.

C. Regulatory Streamlining

The proposed facility is subject to requirements under NSPS that are less stringent than those required in the proposed permit as a result of BACT. The permit has been drafted to reflect the more stringent requirements. Compliance with the more stringent requirements will be deemed as compliance with those that are less stringent. Table 6 summarizes the requirements and demonstrates that the streamlined permit conditions are more stringent. The following analysis demonstrates the permit streamlining.

From NSPS Subpart GG, the emission limit for NO_x from the combustion turbines is established in §60.332(a)(1) as 0.01% by volume at 15% O_2, which corresponds to 75 ppmvd @15% O_2 (without correction for thermal efficiency). NO_x emissions from the turbines will be controlled by DLN combustors and further controlled by an SCR system. The BACT analysis results in an emission rate for NO_x of 2.0 ppmvd @ 15% O_2, on a 3-hour average, which is more stringent than the NSPS Subpart GG requirement. The averaging time may be reduced from 3-hours to 1-hour after the first 18-months of operation based on the NO_x demonstration required by the permit. NSPS Subpart Da establishes an emission limit for NO_x of 0.20 lb/MMBtu for the duct burners. The total NO_x emission rate for each combined cycle system equates to 0.009 lb/MMBtu, which is also more stringent than the NSPS requirement.

The emission limit for SO_2 in NSPS Subpart GG is either a fuel sulfur content of 0.8% by weight or 150 ppmvd. Pipeline quality natural gas is the only fuel to be combusted in the turbines and it is inherently low in sulfur with a maximum allowable sulfur content in the natural gas of 0.75 grains/100 dscf. This equates to a weight percent of sulfur of 0.0024%, which is much lower than the NSPS limit of 0.8% by weight. NSPS Subpart Da establishes an SO_2 emission limit of 0.2 lb/MMBtu for the duct burners. The total SO_2 emission rate for each combined cycle system equates to 0.0021 lb/MMBtu, which is more stringent than the NSPS.

As per 40 CFR part 75, continuous monitoring is required for NO_x, O_2 (or carbon dioxide (CO_2)), and fuel flow. Test methods specified in the permit are more broad and inclusive of the NSPS-specified method. Recordkeeping and reporting requirements in the permit are as stringent as the NSPS.

Table 6. Permit Streamlining Analysis

Citation	Requirements	Proposed Permit Condition	Comparable Level of Stringency
Emission Limits	Turbine: NO_x: 40 CFR 60.332(a)(1), turbine < 75 ppmvd SO_2: 40 CFR 60.333(a), fuel content <0.8% by weight Duct burners: NO_x: 40 CFR 60.44a(a)(1) and (d)(1), ≤ 0.20 lb/MMBtu, 1.6 lb/MW-hr SO_2: 40 CFR 60.43a(b)(2), ≤ 0.2 lb/MMBtu PM: 40 CFR 42a(a)(1) and (b), ≤ 0.03 lb/MMBtu, opacity ≤20% (6-min avg)	Combined cycle units: BACT: 2.0 ppmvd @ 15% O_2, 3 hour average[1] Maximum allowable sulfur content of natural gas 0.75 grains/100 dscf, equates to 0.004 lb/MMBtu PM emission rate equates to 0.01 lb/MMBtu, opacity ≤10% (6-min avg)	Permit more stringent
Monitoring	40 CFR Part 75: CEMS for NO_x and O_2 (or carbon dioxide (CO_2)), and CMS for fuel flow 40 CFR 60.334(b), sulfur and nitrogen content of the fuel, daily or custom schedule	CEMS for NO_x and O_2 (or CO_2), and CMS for fuel flow, sulfur and nitrogen content recorded daily, custom schedule approved by Director	Permit as stringent
Testing	40 CFR 60.8, 60.335(b) and 40 CFR 60.48a, initial source testing and as required by Administrator	Initial performance testing and compliance via CEMS	Permit as stringent
Recordkeeping	40 CFR 60.49a(b), daily records for reporting	Fuel flow monitor and fuel usage records, records of emission rates and CEMS data	Permit as stringent
Reporting	40 CFR 60.7, 60.334(c), 60.49a(h), excess emissions 40 CFR 60.49a(a), performance test data 40 CFR 60.49a(b), reports for SO_2 and NO_x 40 CFR 60.49a(g), signed statement 40 CFR 60.49a(i), semi-annual reports	Semi-annual reports, excess emissions, performance test data, notifications	Permit as stringent

1. This emission limit may be reduced to 2.0 ppmvd on a 1-hour average after the first 18-months of operation based on the NO_x demonstration required by the permit.

V. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

PSD regulations under Title I of the Federal Clean Air Act and A.A.C. R18-2-406.A are applicable to the proposed facility. One of the substantive requirements under the PSD regulations is that, for a new major stationary source, the Best Available Control Technology, or "BACT," must be applied to each emission unit. This requirement applies on a pollutant-specific basis. The facility is subject to the PSD provisions for the following pollutants: PM_{10}, SO_2, NO_X, CO and VOC. The term "best available control technology" is defined at A.A.C. R18-2-101.19 as follows:

> "[A]n emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification."

The procedures for establishing BACT are set forth at A.A.C. R18-2-406.A.4 as follows:

> "BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant. In no event shall such application of BACT result in emissions of any pollutant, which would exceed the emissions allowed by any applicable new source performance standard or national emission standard for hazardous air pollutants under Articles 9 and 11 of this Chapter. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results."

The U.S. EPA's interpretive policies relating to BACT analyses are set forth in several informal guidance documents. Most notable among these are the following:

- "Guidelines for Determining Best Available Control Technology (BACT)," December 1978.
- "Prevention of Significant Deterioration Workshop Manual," October 1980.
- "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting." Draft. October 1990.

The Department generally uses what is termed a "top-down" procedure when making BACT determinations. This procedure is designed to ensure that each determination is made consistent with the two core criteria for BACT: consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions.

The framework for the top-down BACT analysis procedure used by the Department comprises five key steps, as discussed in detail below. The five-step procedure mirrors the analytical framework set forth in the draft 1990 guidance document. However, it should be noted that the Department does not necessarily adhere to the prescriptive process described in the draft 1990 guidance document. Strict adherence to the detailed top-down BACT analysis process described in that draft document would unnecessarily restrict the Department's judgment and discretion in weighing various factors before making case-by-case BACT determinations. Rather, as outlined in the 1978 and 1980 guidance documents, the Department has broad flexibility in applying its judgment and discretion in making these determinations.

Step 1 - Identify all control options. The process is performed on a source-by-source and pollutant-by-pollutant basis and begins with the identification of available control technologies and techniques. For BACT purposes, "available" control options are those technologies and techniques, or combinations of technologies and techniques, with a practical potential for application to the subject emission units and pollutants. These may include fuel cleaning or treatment, inherently lower-polluting processes, and end-of-pipe control devices. All identified control options are listed in this step. Those that are identified as being technically infeasible or as having unreasonable energy, economic or environmental impacts or other unacceptable costs are eliminated in subsequent steps.

Step 2 - Eliminate technically infeasible control options. In this step, the technical feasibility of identified control options is evaluated with respect to source-specific factors. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. In general, if a control option has been demonstrated to function efficiently on the same type of emission unit, or another unit with similar exhaust streams, the control option is presumed to be technically feasible. For presumably technically feasible control options, demonstrations of technical infeasibility must show, based on physical, chemical and engineering principles, that technical difficulties would preclude the control option from being employed successfully on the subject emissions unit. Technical feasibility need not be addressed for control options that are less effective than the control option proposed as BACT by the permit applicant.

Step 3 - Characterize control effectiveness of technically feasible control options. For each control option that is not eliminated in Step 2, the overall control effectiveness for the pollutant under review is characterized. The control option with the highest overall effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no evaluation is required under Step 4, and the procedure moves to Step 5. Otherwise, the top control option and other identified control options that are more effective than that proposed by the permit applicant must be evaluated in Step 4. A control option that can be designed and operated at two or more levels of control effectiveness may be presented and evaluated as two or more distinct control options (i.e., an option for each control effectiveness level).

Step 4 - Evaluate more effective control options. If any identified and technically feasible control options are more effective than that proposed by the permit applicant as BACT, rejection of those more effective control options must be justified based on the evaluation conducted in this step. For each control option that is more effective than the option ultimately selected as BACT, the rationale for rejection must be documented for the public record. Energy, environmental, and economic impacts and other costs of the more effective control options, including both beneficial and adverse (i.e., positive and negative) impacts, are listed and considered.

Step 5 - Establish BACT. Finally, the most effective control technology not rejected in Step 4 is proposed as BACT. To complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, in the case of a numerical emission limitation, the permit must specify a reasonable compliance averaging time, consistent with established reference methods. The permit must also include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S.

EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.

- Information provided by pollution control equipment vendors.
- Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/LAER Clearinghouse.

The BACT evaluations and proposed BACT determinations for each category of emission unit at the facility are discussed in the following subsections.

A. Combined Cycle Systems

The CTG and HRSG units will be equipped with an SCR system and low-NO_x combustors to control NO_x emissions to 2.0 ppmvd at 15% oxygen on a 3-hour average. However, the SCR system will be designed to meet 2.0 ppmvd at 15% oxygen on a 1-hour average. The averaging time may be reduced from 3 hours to 1 hour after the first 18-months of operation based on the NO_x demonstration required by the permit. An oxidation catalyst will control CO and VOC emissions. Combustion controls will mitigate emissions of PM_{10}. Emissions of SO_2 will be limited by a maximum allowable sulfur content in the natural gas of 0.75 grains/100 dscf. These limits are the same for both the GE7FA or the SW501F CTGs, but a BACT analysis was required and performed for both types of turbines.

1. Particulate Matter Less than 10 Microns

For this analysis, PM_{10} is defined to include both fine filterable particulate matter and condensible particulate matter as measured by EPA Reference Methods 201A and 202, respectively. Method 201A measures all particulate matter having an aerodynamic diameter equal to or less than nominally 10 micrometers (10^{-6} meters) that is collected on a glass fiber filter at the stack temperature. Method 201A will generally yield a slightly smaller result than Method 5 because particles having an aerodynamic diameter nominally 10 micrometers or greater are excluded. Method 202 measures all particulate matter that condenses at a temperature of approximately 20 degrees Celsius (ºC) after passing through a fabric filter such as that used in Method 201A. The total PM_{10}, which is the combined result of performing Method 201A and Method 202 simultaneously, may be substantially different than the PM as measured by Method 5.

<u>Steps 1-4</u>

In the original application filed in August 2001, the source did not present a top down BACT analysis and arbitrarily selected the use of pipeline quality natural gas with a PM_{10} content of 10 mg/m^3 as the BACT limit. A top-down analysis was subsequently performed in November 2002, upon request by ADEQ. Although this analysis considered baghouses, ESPs and wet scrubbers, which are technically feasible options, there are no known applications of add-on controls for the purpose of controlling PM_{10} from natural gas-fired units, because this fuel has little, if any , ash that would contribute to the formation of PM or PM_{10}. Table 7 lists PM_{10} emission rates and controls contained in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for other recently permitted similar sources.

<u>Step 5 - Establish BACT</u>

The applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for PM_{10}. The Department agrees with this demonstration.

2. *Nitrogen Oxides*

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural

Table 7. Recent PM_{10} BACT determinations for CTGs and HRSGs							
State	**Permit Date**	**Facility**	**Process**	**Control Technology**	**Emission Limit**	**Emission Limit Units**	**Basis**
MO	6/19/2000	University Of Missouri - Columbia	CT/HRSG	Combustion Controls	9.0	lb/hr	BACT
CA	9/1/2001	Metcalf Energy Center	CT/HRSG		9.0	lb/hr	
ME	9/14/1998	Champion Internatl Corp. & Champ. Clean Energy	CT/HRSG		9.0	lb/hr	BACT
OK	1/21/2000	Oneta Generating Station	CT/HRSG	Use Of Natural Gas	9.4	lb/hr	BACT
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG		9.4	lb/hr	BACT-CA[1]
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG		10.7	lb/hr	BACT-CA
MI	6/7/2001	Renaissance Power LLC	CT/HRSG	Combustion Controls	11.0	lb/hr	BACT
CA	3/1/2001	Mountainview Power Project	CT/HRSG		11.5	lb/hr	BACT-CA
CA	10/1/2000	Blythe Energy	CT/HRSG		12.0	lb/hr	BACT-CA
CA	2/1/2002	Delta Energy Center	CT/HRSG		14.7	lb/hr	
MI	3/16/2000	Southern Energy, Inc.	CT/HRSG		19.0	lb/hr	BACT
OK	12/10/2001	Stephens Energy Facility	CT/HRSG		19.1	lb/hr	BACT
CA	4/1/2001	Otay Mesa Generating Project	CT/HRSG		20.0	lb/hr	
FL	9/7/2001	El Paso Belle Glade Energy Center	CT/HRSG	Use Of Natural Gas	20.0	lb/hr	BACT
FL	8/17/2001	El Paso Broward Energy Center	CT/HRSG	Use Of Natural Gas	20.0	lb/hr	BACT
FL	9/11/2001	El Paso Manatee Energy Center	CT/HRSG	Use Of Natural Gas	21.8	lb/hr	BACT
MA	4/16/1999	ANP Blackstone Energy Company	CT/HRSG	Use Of Natural Gas	21.8	lb/hr	BACT
MA	8/4/1999	ANP Bellingham Energy Company	CT/HRSG	Use Of Natural Gas	22.6	lb/hr	BACT
MO	8/19/1999	Kansas City Power & Light Co. - Hawthorn Station	CT/HRSG	Combustion Controls	24.0	lb/hr	BACT
AZ	2/15/2001	Harquahala Generating Project	CT/HRSG	Combustion Controls	27.8	lb/hr	BACT
AR	12/29/2000	Duke Energy Hot Springs	CT/HRSG	Combustion Controls	29.4	lb/hr	BACT
MN	11/17/2000	Xcel Energy, Black Dog Electric Generating Station	CT/HRSG	Use Of Natural Gas	29.4	lb/hr	BACT
AZ	Draft - 2003	La Paz Generating Facility (W501F)	CT/HRSG		30.3	lb/hr	BACT
AZ	Draft - 2003	La Paz Generating Facility (GE 7FA)	CT/HRSG		45.5	lb/hr	BACT
[1] BACT-CA = California BACT							

Table 8. Recent NOx BACT determinations for CTGs and HRSGs

State	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Units	Basis
MA	9/11/2000	IDC Bellingham	CT/HRSG	SCR	1.5	PPM	LAER
CA	4/1/2001	Otay Mesa Generating Project	CT/HRSG	SCR	2.0	PPM	BACT-CA
RI	5/3/2000	Reliant Energy Hope Generating Facility	CT/HRSG	SCR	2.0	PPM	BACT
MA	1/25/2000	Sithe Mystic Development	CT/HRSG	SCR	2.0	PPM	LAER
CA	5/1/2001	Three Mountain Power	CT/HRSG	SCR	2.0	PPM	BACT-CA
FL	8/17/2001	El Paso Broward Energy Center	CT/HRSG	SCR	2.5	PPM	BACT
AZ	3/22/2001	Mesquite Generating Station	CT/HRSG	SCR	2.5	PPM	BACT
PA	10/10/2000	Calpine Construction Finance Co., LP	CT/HRSG	SCR	2.5	PPM	LAER
FL	9/11/2001	El Paso Manatee Energy Center	CT/HRSG	SCR	2.5	PPM	BACT
FL	9/7/2001	El Paso Belle Glade Energy Center	CT/HRSG	SCR	2.5	PPM	BACT
AZ	2/15/2001	Harquahala Generating Project	CT/HRSG	SCR	2.5	PPM	BACT
CA	2/1/2002	Delta Energy Center	CT/HRSG	SCR	2.5	PPM	
CA	3/30/2000	Elk Hills Power Project	CT/HRSG	SCR	2.5	PPM	BACT-CA
CA	3/1/2001	Mountainview Power Project	CT/HRSG	SCR	2.5	PPM	BACT-CA
CA	10/1/2000	Blythe Energy	CT/HRSG	SCR	2.5	PPM	BACT-CA
CA	5/1/2001	Contra Costa Unit 8 Power Project	CT/HRSG	SCR	2.5	PPM	
NH	4/26/1999	Newington Energy LLC	CT/HRSG	SCR	2.5	PPM	BACT
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG	SCR	2.5	PPM	BACT-CA
NH	4/26/1999	AES Londonderry, LLC	CT/HRSG	SCR	2.5	PPM	BACT
CA	9/1/2001	Metcalf Energy Center	CT/HRSG	SCR	2.5	PPM	
ME	12/4/1998	Westbrook Power LLC	CT/HRSG	SCR	2.5	PPM	LAER
MI	6/7/2001	Renaissance Power LLC	CT/HRSG	SCR	3.5	PPM	BACT
OK	12/10/2001	Stephens Energy Facility	CT/HRSG	SCR	3.5	PPM	BACT
OK	6/13/2002	Genova OK I Power Project	CT/HRSG	SCR	3.5	PPM	BACT
AR	12/29/2000	Duke Energy Hot Springs	CT/HRSG	SCR	3.5	PPM	BACT

BACT-CA = California BACT

Table 9a. Summary of Top-Down BACT Cost Analysis for NOx										
					Economic Impacts			Environmental Impacts		Energy Impacts
Engine Model	Control Alternative	Emissions (tpy)	Emissions Reduction (tpy)	Control Efficiency (percent)	Total Annualized Cost ($/yr)	Average cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (yes/no)	Adverse Environ-mental Impacts (yes/no)	Incremental Increase over Baseline (MMBtu/yr)
W501F	DLN/SCR 2.0 ppm	80	918	92%	$2,455,121	$2,675	$5,093	no	yes[1]	17,887
W501F	DLN/SCR 2.5 ppm	100	898	90%	$2,353,506	$2,622	$2,622	no	yes[1]	17,688
W501F	Uncontrolled Baseline	998	-	-	-	-	-	-	-	-
[1] NH_3 and disposal of catalyst										

Table 9b. Summary of Top-Down BACT Cost Analysis for NOx										
					Economic Impacts			Environmental Impacts		Energy Impacts
Engine Model	Control Alternative	Emissions (tpy)	Emissions Reduction (tpy)	Control Efficiency (percent)	Total Annualized Cost ($/yr)	Average cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (yes/no)	Adverse Environ-mental Impacts (yes/no)	Incremental Increase over Baseline (MMBtu/yr)
GE 7FA	DLN/SCR 2.0 ppm	70	245	78%	$2,321,991	$9,478	$6,225	no	yes[1]	15,827
GE 7FA	DLN/SCR 2.5 ppm	88	228	72%	$2,213,053	$9,728	$9,728	no	yes[1]	15,319
GE 7FA	Uncontrolled Baseline	315	-	-	-	-	-	-	-	-
[1] NH_3 and disposal of catalyst										

Table 9c. Summary of Top-Down BACT Cost Analysis for Combined NO_x and CO

					Economic Impacts			Environmental Impacts		Energy Impacts
Engine Model	**Control Alternative**	**Emissions (tpy)**	**Emissions Reduction (tpy)**	**Control Efficiency (percent)**	**Total Annualized Cost ($/yr)**	**Average cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**Toxics Impact (yes/no)**	**Adverse Environ-mental Impacts (yes/no)**	**Incremental Increase over Baseline (MMBtu/yr)**
W 501F	EMx - NOx 2.0 ppm, CO 2.0 ppm	128	1,287	91%	$6,827,197	$5,304	$5,304	no	yes[2]	39,994
W 501F	SCR/OC[1] - NOx 2.0 ppm, CO 2.0 ppm	128	1,176	83%	$3,302,379	$2,808	$2,808	no	yes[3]	21,219
W 501F	Uncontrolled Baseline	1,415	-		-	-	-	-	-	-

[1] SCR/OC – Combined SCR and oxidation catalyst
[2] 75,000 gallons of caustic wash annually
[3] NH_3 and disposal of catalyst

Table 9d. Summary of Top-Down BACT Cost Analysis for Combined NO_x and CO										
					Economic Impacts			**Environmental Impacts**		**Energy Impacts**
Engine Model	**Control Alternative**	**Emissions (tpy)**	**Emissions Reduction (tpy)**	**Control Efficiency (percent)**	**Total Annualized Cost ($/yr)**	**Average cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**Toxics Impact (yes/no)**	**Adverse Environ-mental Impacts (yes/no)**	**Incremental Increase over Baseline (MMBtu/yr)**
GE 7FA	EMx - NOx 2.0 ppm, CO 2.0 ppm	113	394	78%	$6,426,417	$16,307	$16,307	no	yes[2]	39,994
GE 7FA	SCR - NOx 2.0 ppm, ox cat 2.0 ppm	113	283	56%	$3,169,249	$11,195	$11,195	no	yes[3]	21,160
GE 7FA	Uncontrolled Baseline	507	-		-	-	-	-	-	-

[1] SCR/OC – Combined SCR and oxidation catalyst
[2] 75,000 gallons of caustic wash annually
[3] NH_3 and disposal of catalyst

Table 10. Recent CO BACT determinations for CTGs and HRSGs

State	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Units	Basis
MA	9/11/2000	IDC Bellingham	CT/HRSG	Oxidation Catalyst	2.0	PPM	
MA	1/25/2000	Sithe Mystic Development	CT/HRSG	Oxidation Catalyst	2.0	PPM	BACT
MI	2/8/1999	Wyandotte Energy	CT/HRSG	Oxidation Catalyst	3.0	PPM	LAER
MI	6/7/2001	Renaissance Power LLC	CT/HRSG	Oxidation Catalyst	3.0	PPM	BACT
CA	3/30/2000	Elk Hills Power Project	CT/HRSG	Oxidation Catalyst	4.0	PPM	BACT-CA
AZ	3/22/2001	Mesquite Generating Station	CT/HRSG	Oxidation Catalyst	4.0	PPM	BACT
CA	5/1/2001	Three Mountain Power	CT/HRSG		4.0	PPM	BACT-CA
CA	10/1/2000	Blythe Energy	CT/HRSG		5.0	PPM	BACT-CA
CA	5/1/2001	Contra Costa Unit 8 Power Project	CT/HRSG		6.0	PPM	BACT-CA
CA	4/1/2001	Otay Mesa Generating Project	CT/HRSG		6.0	PPM	
CA	9/1/2001	Metcalf Energy Center	CT/HRSG		6.0	PPM	
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG	Oxidation Catalyst	6.0	PPM	BACT-CA
CA	3/1/2001	Mountainview Power Project	CT/HRSG	Oxidation Catalyst	6.0	PPM	BACT-CA
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG	Oxidation Catalyst	6.0	PPM	BACT-CA
FL	9/11/2001	El Paso Manatee Energy Center	CT/HRSG	Combustion Controls	7.4	PPM	BACT
FL	9/7/2001	El Paso Belle Glade Energy Center	CT/HRSG	Combustion Controls	7.4	PPM	BACT
FL	8/17/2001	El Paso Broward Energy Center	CT/HRSG	Combustion Controls	7.4	PPM	BACT
OK	1/21/2000	Oneta Generating Sta	CT/HRSG	Combustion Controls	7.8	PPM	BACT
OK	6/13/2002	Genova OK I Power Project	CT/HRSG	Combustion Controls	8.2	PPM	BACT
IN	6/6/2001	Duke Energy, Vigo LLC	CT/HRSG	Combustion Controls	9.0	PPM	BACT
CO	6/19/2000	Fort St. Vrain	CT/HRSG	Combustion Controls	9.0	PPM	BACT
ME	9/14/1998	Champion Intl Corp. & Champ. Clean Energy	CT/HRSG		9.0	PPM	BACT
OK	3/24/1999	Chouteau Power Plant	CT/HRSG	Combustion Controls	10.0	PPM	BACT
OK	12/10/2001	Stephens Energy Facility	CT/HRSG		10.0	PPM	BACT
PA	10/10/2000	Calpine Construction Finance Co., LP	CT/HRSG		10.0	PPM	BACT
CA	2/1/2002	Delta Energy Center	CT/HRSG		10.0	PPM	

BACT-CA = California BACT

Table 11a. Summary ofTop-Down BACT Cost Analysis for CO										
					Economic Impacts			Environmental Impacts		Energy Impacts
Engine Model	Control Alternative	Emissions (tpy)	Emissions Reduction (tpy)	Control Efficiency (percent)	Total Annualized Cost ($/yr)	Average cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (yes/no)	Adverse Environ-mental Impacts (yes/no)	Incremental Increase over Baseline (MMBtu/yr)
W501F	Oxidation Catalyst 2.0 ppm	49	373	89%	$781,077	$2,092	$3,528	no	no	3,333
W501F	Oxidation Catalyst 3.0 ppm	74	348	83%	$691,779	$1,988	$1,988	no	no	3,333
W501F	Baseline	422	-	-	-	-	-	-	-	-

Table 11b. Summary of Top-Down BACT Cost Analysis for CO										
					Economic Impacts			Environmental Impacts		Energy Impacts
Engine Model	Control Alternative	Emissions (tpy)	Emissions Reduction (tpy)	Control Efficiency (percent)	Total Annualized Cost ($/yr)	Average cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Toxics Impact (yes/no)	Adverse Environ-mental Impacts (yes/no)	Incremental Increase over Baseline (MMBtu/yr)
GE 7FA	Oxidation Catalyst 2.0 ppm	42	151	78%	$820,786	$5,448	$4,020	no	no	5,333
GE 7FA	Oxidation Catalyst 3.0 ppm	65	128	67%	$731,487	$5,695	$5,695	no	no	5,333
GE 7FA	Baseline	193	-	-	-	-	-	-	-	-

Table 12. Recent VOC BACT determinations for CTGs and HRSGs							
State	Permit Date	Facility	Process	Control Technology	Emission	Emission Limit	Basis

					Limit	Units	
ME	12/4/1998	Westbrook Power Llc	CT/HRSG		0.4	PPM	BACT
MA	9/11/2000	Idc Bellingham	CT/HRSG	Oxidation Catalyst	1.0	PPM	
CA	10/1/2000	Blythe Energy	CT/HRSG		1.0	PPM	BACT-CA
ME	7/13/1998	Casco Ray Energy Co	CT/HRSG		1.0	PPM	BACT
OK	1/21/2000	Oneta Generating Sta	CT/HRSG		1.2	PPM	BACT
FL	9/11/2001	El Paso Manatee Energy Center	CT/HRSG	Combustion Controls	1.4	PPM	BACT
FL	8/17/2001	El Paso Broward Energy Center	CT/HRSG	Combustion Controls	1.4	PPM	BACT
OK	12/10/2001	Stephens Energy Facility	CT/HRSG		1.4	PPM	BACT
FL	9/7/2001	El Paso Belle Glade Energy Center	CT/HRSG	Combustion Controls	1.4	PPM	BACT
WV	12/18/2001	Panda Culloden Generating Station	CT/HRSG	Combustion Controls	1.4	PPM	BACT
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG	Oxidation Catalyst	1.4	PPM	BACT-CA
MA	1/25/2000	Sithe Mystic Development	CT/HRSG	Oxidation Catalyst	1.7	PPM	LAER
PA	10/10/2000	Calpine Construction Finance Co., LP	CT/HRSG		1.8	PPM	LAER
RI	2/13/1998	Tiverton Power Associates	CT/HRSG	Combustion Controls	2.0	PPM	BACT
CA	4/1/2001	Otay Mesa Generating Project	CT/HRSG		2.0	PPM	
CA	5/1/2001	Three Mountain Power	CT/HRSG		2.0	PPM	BACT-CA
AZ	2/15/2001	Harquahala Generating Project	CT/HRSG	Combustion Controls	2.8	PPM	BACT
RI	5/3/2000	Reliant Energy Hope Generating Facility	CT/HRSG		2.9	PPM	BACT
FL	11/22/1999	Oleander Power Project	CT/HRSG	Combustion Controls	3.0	PPM	BACT
MI	6/7/2001	Renaissance Power LLC	CT/HRSG	Combustion Controls	4.0	PPM	BACT
OK	6/13/2002	Genova OK I Power Project	CT/HRSG	Combustion Controls	4.1	PPM	BACT
MI	2/8/1999	Wyandotte Energy	CT/HRSG		6.0	PPM	BACT
OK	2/12/2002	Horseshoe Energy Project	CT/HRSG	Oxidation Catalyst	6.0	PPM	BACT
OK	5/17/2001	Thunderbird Power Plant	CT/HRSG		7.0	PPM	BACT
OK	10/1/1999	Green Country Energy Project	CT/HRSG	Combustion Controls	7.0	PPM	BACT
OK	8/15/2001	Redbud Power Plant	CT/HRSG	Combustion Controls	7.0	PPM	BACT
BACT-CA = California BACT							

Table 13. Recent SO_2 BACT determinations for CTGs and HRSGs							
State	**Permit Date**	**Facility**	**Process**	**Control Technology**	**Emission Limit**	**Emission Limit Units**	**Basis**
OK	3/24/1999	Chouteau Power Plant	CT/HRSG	Use Of Natural Gas	1.0	LB/HR	
CA	5/1/2001	Three Mountain Power	CT/HRSG		1.2	LB/HR	BACT-CA
CA	3/1/2001	Mountainview Power Project	CT/HRSG		1.4	LB/HR	CA-BACT
CA	2/1/2002	Delta Energy Center	CT/HRSG		1.5	LB/HR	
AZ	3/22/2001	Mesquite Generating Station	CT/HRSG	Use Of Natural Gas	2.1	LB/HR	BACT
OK	1/21/2000	Oneta Generating Station	CT/HRSG	Use Of Natural Gas	2.5	LB/HR	BACT
CA	10/1/2000	Blythe Energy	CT/HRSG		2.7	LB/HR	BACT-CA
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG		3.8	LB/HR	BACT-CA
CA	3/1/2001	Western Midway Sunset Power Project	CT/HRSG		3.9	LB/HR	BACT-CA
MA	8/4/1999	ANP Bellingham Energy Company	CT/HRSG	Use Of Natural Gas	4.2	LB/HR	BACT
WV	12/18/2001	Panda Culloden Generating Station	CT/HRSG	Use Of Natural Gas	5.4	LB/HR	BACT
AZ	2/15/2001	Harquahala Generating Project	CT/HRSG	Use Of Natural Gas	5.8	LB/HR	BACT
MA	5/7/2000	Cabot Power Corporation	CT/HRSG	Use Of Natural Gas	5.9	LB/HR	BACT
MS	3/27/2001	Caledonia Power LLC	CT/HRSG		12.0	LB/HR	BACT
ME	9/14/1998	Champion Internatl Corp. & Champ. Clean Energy	CT/HRSG		12.0	LB/HR	BACT
BACT-CA = California BACT							

gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

In the original application filed in August 2001, the source did not present a top down BACT analysis and arbitrarily selected SCR with DLN as BACT to achieve a limit of 2.5 ppmvd at 15% O_2 on a 3-hour average as the BACT limit. A top-down analysis was subsequently performed in November 2002, upon request by ADEQ. This analysis considered water steam injection, DLN combustors, XONON, SNCR, SCR and EMx™ (a proprietary SCONOx system produced by EmeraChem, LLC).

<u>Step 1 - Identify all control options.</u>

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment (i.e., NO_x is removed from the exhaust stream after it is generated). A number of measures exist for the control of NO_x emissions, including both in-combustor controls, such as water (or steam) injection, the use of DLN combustors and XONON, and post-combustion systems such as SCR, SCONOx and Selective Non Catalytic Reduction (SNCR). A comparison of the control systems permitted as BACT in recent projects taken from the RBLC is presented in Table 8.

For large gas turbines such as those proposed for this project, water and steam injection have been largely superseded by DLN combustors, due to the superior emission control performance and increased efficiency. DLN combustors are also effective in achieving lower NO_x emission levels without the need for large volumes of purified water. Both DLN burners and water injection result in higher VOC and CO emissions than uncontrolled turbines, but these effects will be minimized by high combustion temperatures, adequate excess air, and good air-to-fuel mixing during combustion.

The Catalytica XONON combustion system improves the combustion process by lowering the peak combustion temperature to reduce the formation of NO_x, while further controlling CO and VOC emissions. The key feature of the XONON combustion system is a proprietary catalytic component called the XONON module, which is integral to the gas turbine combustor. XONON combusts the fuel without a flame, thus eliminating the peak flame temperatures that leads to the formation of NO_x. Because this technology is based on preventing NO_x formation rather than removing it after it is formed, no expensive add-on recovery system is required.

The SCR process is a post-combustion control technology in which injected NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_x emission reduction is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in an undesirable increase in levels of unreacted NH_3 (called ammonia slip).

SCR has been demonstrated to be effective at numerous installations throughout the United States. Typically SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled.

SCONOx is another type of post-combustion control. The EMx™ SCONOx system reviewed by the source uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. It is operated in the 300-700 ^{0}F temperature range. The nitrogen oxide (NO) present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of nitrogen (N_2) and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no O_2 present during this step, so dampers are used to isolate the catalyst for regeneration. The CO present in the flue gas is oxidized to CO_2.

In the SNCR process, ammonia or urea is injected into the exhaust stream, which reacts with NO in a series of reactions that reduce NO to N_2. To be effective, this reaction must take place within a narrow range of high temperatures (1500 -2000 ^{0}F). At temperatures below this range, there would be increased ammonia slip and at temperatures above this range, ammonia or urea can be oxidized to form NO.

<u>Steps 2-4</u>

Water steam injection was rejected because it is not capable of reducing NO_x concentrations to current BACT limits. XONON was rejected on technical considerations because it is an emerging technology and is not commercially available at this time for CTGs of the size proposed for this project.

SNCR was also rejected on technical considerations because the exhaust temperature of the CTG would be 1200 ^{0}F, which falls below the range in which SNCR is effective, and which, would result in increased ammonia slip. EMx™ was rejected as a technically infeasible operation without operational data for a F class turbine.

<u>Step 5 - Establish BACT</u>

After considering the data that was submitted, and the emission limits for other recently permitted projects, ADEQ agrees with the applicant's analysis that DLN combustors in combination with an SCR control system that reduces NO_x to 2.0 ppmvd at 15% O_2 on a 3-hour average represents BACT for each CTG and HRSG. The 3-hour averaging time may be revised down to 1-hour after 18-

months of operation as per the NO_x demonstration required in the permit. Although ADEQ is not aware of any similar sized facility with duct burners that has demonstrated that 2.0 ppmvd on a 1-hour basis has been achieved in practice, ADEQ is including the 18-month demonstration period given that 1) the 2.0 ppmvd, 1-hour average NO_x BACT limit has been demonstrated on a facility that does not utilize duct burners, 2) it is consistent with other recently permitted combined cycle system sources in EPA Region IX.

The permit states that the averaging time will be reduced to 1-hour, excluding periods of start-up and shutdown, after the first 18-months of operation. If the facility has not been able to reasonably and consistently meet a NO_x limit of 2.0 ppmvd on a 1-hour average, the applicant is required to submit a written request to the Director and the Administrator prior to the 18-month deadline, based on the first 12-months of operational data, requesting a different averaging time that is not to exceed 3-hours. The Director and Administrator will review the request before determining the final emission limit for the remaining permit term.

As noted above, operation of SCR systems can result in undesired emissions of unreacted NH_3, or ammonia slip. Other similar sources permitted in EPA Region IX have been limited to 10 ppmvd NH_3. Given that source is not in operation, a lower ammonia slip level in conjunction with the lower NO_x limit has not been demonstrated. Consequently, ADEQ is establishing a conditional ammonia slip emission limit of 10 ppmvd at 15% O_2 on a 24-hour rolling average for the first 18-months of operation, with a similar demonstration period as NO_x, that may reduce the ammonia emission limit to 7.5 ppmvd on a 24-hour rolling average.

3. *Carbon Monoxide*

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_x during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

In the original application filed in August 2001, the source did not present a top down BACT analysis and arbitrarily selected the use of an oxidation catalyst to reduce CO emissions to 5 ppmvd at 15% O_2 as the BACT limit. A top-down analysis was subsequently performed in November 2002, considering the use of combustion design/control, an oxidation catalyst and EMx™.

<u>Step 1- Identify all control options</u>

Combustion technology for large gas turbines has advanced considerably and emissions in the range of 9-15 ppmvd can be achieved by this technology when the turbines are operating at base load conditions. Catalytic oxidation is a post-combustion method for reduction of CO and VOC emissions, which has been successfully applied to natural gas-fired turbines in cogeneration and combined cycle systems for about 10 years. Excess oxygen in the turbine exhaust reacts with CO and VOC over the catalyst bed to promote the oxidation and formation of CO_2 and H_2O. No injection of reagent is necessary and none of the catalyst components are considered toxic. The EMx™ SCONOx system oxidizes the CO present in the flue gas to CO_2.

Recent BACT determinations for CO obtained from the RBLC are shown in Table 10. A review of the RBLC data in Table 10 indicates that combined cycle projects have recently been permitted with oxidation catalysts to achieve emissions lower than 7 ppmvd.

Steps 2-4

Combustion design and control was rejected because it is not capable of reducing CO concentrations to the 2-5 ppmvd levels that have been demonstrated by recently permitted sources utilizing oxidation catalyst technology. EMx™ was rejected because it has not been demonstrated on F class turbines. Based on the top down approach that was required by ADEQ, the source initially proposed a limit of 5 ppmvd with an oxidation catalyst as the CO BACT limit, which represents the most stringent control option that is available for this pollutant. The company later revised the proposed 5 ppmvd limit to 3 ppmvd in April 2003, after considering recent combined cycle permitting actions in Arizona. A costing analysis was also carried out for 2 ppmvd, but ADEQ determined that the incremental costs to achieve this level of emissions would be economically unreasonable.

Step 5- Establish BACT

ADEQ concurs with the applicant's BACT proposal of utilizing an oxidation catalyst to limit CO emissions to 3 ppmvd at 15% O_2 on a 3-hour average.

4. Volatile Organic Compounds

The proposed combustion turbines and duct burners are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines and duct burners incorporate state-of-the-art combustion technology, and both are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (approximately 94% by volume) and ethane (approximately 4% by volume), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100% combusted. The high energy efficiency of turbines and duct burners and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine/duct burner systems because the conditions required for recombination are not present.

In the original application filed in August 2001, the source did not present a top down BACT analysis and arbitrarily selected the use of an oxidation catalyst to reduce VOC emissions to 5 ppmvd at 15% O_2 as the BACT limit. A top-down analysis was subsequently performed in November 2002, considering the use of combustion design/control, an oxidation catalyst and EMx™.

<u>Step 1- Identify all control options</u>

Combustion technology for large gas turbines has advanced considerably and emission in the range of 1-2 ppmvd can be achieved by this technology when the turbines are operating at base load conditions. Catalytic oxidation is a post-combustion method for reduction of CO and VOC emissions, which has been successfully applied to natural gas-fired turbines in cogeneration and combined cycle systems for about 10 years. Excess oxygen in the turbine exhaust reacts with CO and VOC over the catalyst bed to promote the oxidation and formation of CO_2 and H_2O. No injection of reagent is necessary and none of the catalyst components are considered toxic. The EMx™ SCONOx system oxidizes the VOC present in the flue gas to CO_2 and H_2O.

Recent BACT determinations for VOC obtained from the RBLC are shown in Table 12.

<u>Steps 2-4</u>

EMx™ was rejected because it has not been demonstrated on large turbines such as the F class turbines. Based on the top down approach that was required by ADEQ, the source initially proposed a limit of 5 ppmvd with an oxidation catalyst as the VOC BACT limit.

The company later revised the proposed 5 ppmvd limit to 3 ppmvd in April 2003, after considering recent combined cycle permitting actions in Arizona. A costing analysis was also carried out for 2 ppmvd, but ADEQ determined that the incremental costs to achieve this level of emissions would be economically unreasonable.

<u>Step 5- Establish BACT</u>

ADEQ concurs with the applicant's BACT proposal of utilizing an oxidation catalyst to limit VOC emissions to 3 ppmvd at 15% O_2 on a 3-hour average.

5. Sulfur Dioxide

<u>Step 1-4</u>

Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Although there are no known applications of add-on controls for the purpose of controlling SO_2 from natural gas-fired units, the source identified wet and dry limestone scrubbers as possible controls in addition to low sulfur fuel. Add-on control devices are typically used to control emissions from sources firing fuels with higher sulfur content, such as coal. The proposed combustion turbines and duct burners will be designed and operated with natural gas, which is inherently low in sulfur, so add-on controls were not considered because the realizable emission reduction is far too small for the controls to be cost-effective.

Table 13 shows recent BACT determinations for SO_2. It is evident from this table that there is no precedent for add-on controls to limit SO_2 emissions from combustion turbines firing natural gas.

Step 5- Establish BACT

The applicant has demonstrated that the use of good combustion practices and use of natural gas represents BACT for SO_2. The SO_2 emissions will be reduced by limiting the maximum allowable sulfur content in the natural gas to 0.75 grains/100 dscf and including an SO_2 emission limit of 0.0023 lb/MMBtu for either type of turbine.

B. Cooling Towers

Particulate matter is emitted from wet cooling towers due to the presence of suspended and dissolved solids in water droplets that drift from the cooling tower. As a droplet that drifts from the tower evaporates, the dissolved solids present in the droplet agglomerate into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present in the droplet, and the density of the resulting particle.

Step 1 - Identify all control options

Dry cooling towers and drift eliminators were identified as control options to reduce PM and PM_{10} emissions. A dry cooling tower is an inherently less-polluting alternative to a wet cooling tower. This type of cooling tower circulates the process water through a large bank of radiator coils. These coils are cooled by forced flow of ambient air on the outer finned surfaces of the radiator. Ambient airflow is driven by very large axial propeller fans, typically located below the radiator bank, so that the air is blown upward through the radiator and the warmer air exits the top of the tower. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, a dry cooling tower would not be a source of particulate matter emissions.

Drift eliminators are located perpendicular to the air flow and are designed to collect and remove condensed water droplets from the air stream. Changes of direction in the air flow passing through the eliminator promotes removal of droplets by coagulation and impaction on the eliminator surfaces. Particulate matter emissions are thus minimized as drift is minimized.

Steps 2-4

Although both technologies are technically feasible, the applicant provided cost data that demonstrated that dry cooling technology was not economically feasible when compared to wet cooling. Operation and maintenance costs are lower for dry cooling because water treatment costs are eliminated, but the capital costs were shown to be about two times higher due to the increased number of fans and motors and the additional heat transfer surface that is required to provide equivalent cooling capacity.

Step 5- Establish BACT

The Permittee proposed the use of drift eliminators as BACT, with a vendor-guaranteed maximum total liquid drift of 0.0005 percent of the circulating water flow rate. This is equivalent to the most stringent equipment specification for wet cooling towers. The

Department concurs that this proposal represents BACT.

It should be noted that emission testing is not feasible for wet cooling towers due to exhaust characteristics, so the BACT determination is expressed as an equipment specification rather than an emission limit.

C. Auxiliary Boiler

Steps 1-4

The Permittee identified in-furnace formation control, such as low NO_x burners and flue gas recirculation, and post-combustion emissions control, such as SCR and SNCR, as possible control technologies for NO_x. However, the emissions from the auxiliary boiler are so low that, except for the low NO_x burners, all the controls identified are not cost-effective because of their high capital costs. For the same reason, an oxidation catalyst for the control of VOC and CO is not considered cost effective.

Since the boiler will be operated with natural gas, which results in low sulfur dioxide and particulate emissions, add-on controls were not considered for these pollutants because the realizable reduction in emissions is far too small for the controls to be cost-effective.

Step 5- Establish BACT

Low-NO_x burners and good combustion practices that are guaranteed to result in emissions of 16 ppm have been identified and accepted as BACT for NO_x, which was used to calculate the 0.37 lb/MMBtu limit in the permit. Good combustion practices, operating the equipment according to manufacturer specifications and the use of natural gas have been identified and accepted as BACT for CO, VOC, PM_{10}, and SO_2. The limits in the permit for these pollutants are based on guarantees that are provided by the manufacturer. Records of these guarantees are required to be maintained at all times in the facility.

D. Black Start Generators and Fire Pump

The proposed facility will operate two 6 MW natural gas black start engines and a 300 hp diesel fire pump. Each engine will be permitted to operate for a maximum of 200 hours per year, but actual operation is expected to be considerably less. Although a BACT analysis was performed, annual emissions from these units are small enough to the point of being negligible.

Steps 1-4

For all of the units, identified control technologies and techniques for reducing NO_x emissions include combustion modifications, such as ignition timing retard and pre-chamber ignition, and post-combustion control devices, such as SCR or non-catalytic SCR (NSCR). Identified control technologies and techniques for CO emissions include combustion modifications, such as lean burn fuel mix and pre-chamber ignition and post-combustion control devices such as catalytic oxidation or NSCR. NSCR is not considered a technically feasible option to control NO_x and CO emissions and was eliminated from the the analysis. The highest ranked option was identified as SCR for NO_x and an oxidation catalyst for CO. The second ranked option for both was identified as good combustion controls. The emissions from the generators are so low that SCR and catalytic oxidation will not be cost-effective because of their high capital costs.

Since the generators will be operated with natural gas, which results in almost negligible particulate, SO_2 and VOC emissions, add-on controls were not considered for these pollutants because the realizable reduction in emissions is far too small for the controls to be cost-effective.

Step 5- Establish BACT

The Department considers BACT for NO_X and CO emissions from the black start engines to be combustion controls designed to achieve a NO_X emission level of 1.5 grams per brake horsepower-hour output (g/bhp-hr) and a CO emissions level of 2.3 g/bhp-hr. Due to the very low emissions from these sources, and due to the availability of engines that are certified to achieve these emission levels, the Department has determined that equipment design standards rather than emission rate limits are appropriate. Compliance with the equipment design standards will be demonstrated by maintaining records of the engine manufacturer's emission performance guarantees.

Because of the small size of the fire pump engine, no BACT limits were specified for this unit, with the exception of a sulfur content for the diesel fuel of 0.05%.

VI. MONITORING REQUIREMENTS

A. Combined Cycle Systems

Pursuant to 40 CFR 64.2(b)(iii), the facility is not subject to CAM for NO_x because it is subject to Acid Rain Program requirements, and is not subject to CAM for CO because the facility will install a CEMS to measure CO emissions from the turbines.

PM: The units are subject to a PM_{10} emission limitation because of BACT requirements, which includes the use of pipeline quality natural gas and employing good combustion practices. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Opacity: The Combined Cycle Systems are subject to the opacity standard of 10% as is consistent with previous permitting projects in the state (i.e., Griffith Energy, Bowie Power Project). Natural gas is a clean burning fuel and operation of these types of units generally indicate that opacity problems are rare.

NO_x: The units are subject to a NO_x emission limitation because of BACT requirements. The source is required to operate, certify, maintain, and calibrate compliance CEMS for NO_x. The CEMS must comply with the applicable requirements of 40 CFR Part 75. A Relative Accuracy Test Audit (RATA) is required annually for the monitors. The source is also required to develop an Operations and Maintenance plan for the SCR system.

CO: The units are subject to a CO emission limitation because of BACT requirements. The source is required to operate, certify, maintain, and calibrate compliance CEMS for CO. The CEMS must comply with the applicable provisions of 40 CFR Part 60 and 40 CFR Part 75. A RATA is required annually for the monitors.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100 dscf in the natural gas and a limit of 4.7 pounds per hour (lb/hr) for the GE7FA turbine configuration and 5.3 lb/hr for the SW501F turbine configuration. The permit requires daily monitoring for SO_2, and allows for custom monitoring protocols to be used that are pre-approved by the Director.

VOC: The units are subject to a VOC emission limitation due to the additional benefits resulting from the use of BACT to control CO emissions. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Ammonia: The units are subject to an ammonia slip emission limit. The source is required to operate, certify, maintain, and calibrate ammonia flow meters on each SCR unit to monitor the ammonia injection rate.

Flow and Diluent: As per 40 CFR Part 75, fuel flow meters are required on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. O_2 (or CO_2) diluent gas monitors are required on each combined cycle system. The monitors will comply with the applicable provisions of 40 CFR Part 60 (Appendices B and F) and 40 CFR Part 75.

B. Cooling Tower

PM: To ensure that the limit of 3.0 lb/hr is not exceeded, the source is required to record the total dissolved solids (TDS) of the circulating water once per month. Along with the records of the design maximum pumping capacity of the water pump and the design liquid drift rate of 0.0005%, the monthly measurement of the TDS should be used to calculate the PM emission rate from the cooling tower every month.

Opacity: EPA Reference Method 22 observations should be performed daily when operations are commenced. If no visible observations occur for seven consecutive days, then the frequency of opacity readings can be reduced to once a week, which can be further reduced to once a month if no visible emissions occur for four consecutive weeks. However, if visible emissions are observed during a weekly or monthly test, then the frequency of readings will revert to daily until no emissions are seen for seven consecutive days.

C. Auxiliary Boiler, Black Start Generators and Fire Pump

Opacity: EPA Reference Method 9 or 22 observations should be made once per quarter. If the equipment is not operated in a certain quarter, then, an opacity reading is not required but a log entry should be made stating this fact.

VII. TESTING REQUIREMENTS

Performance testing is one component used to demonstrate compliance with the emission rates in the permit. Specifications regarding the test plan, sampling facilities, and reports are included in the General Provisions (Attachment “A”) of the permit. Test methods are specified in the permit and testing must be performed at full load and at reduced load conditions.

A. Combined Cycle Systems with Duct Firing

The source is required to perform initial performance tests for PSD pollutants. Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the RATA for the CEMS. Performance testing for ammonia at full load with duct firing will be conducted initially and every two years thereafter. Catalyst life expectancy for the SCR is typically given as three years. Therefore, performing a stack test every two years will determine if there is early catalyst degradation. An initial performance test and annual tests thereafter for PM_{10} and VOC will be used to demonstrate compliance with the PM_{10} and VOC emission limits. An initial performance test for SO_2 will be used to demonstrate compliance with the SO_2 lb/hr emission limitation.

B. Auxiliary Boilers

The source is required to perform an initial performance test for NO_x, CO, SO_2, VOC, and PM_{10} emissions from the auxiliary boiler.

VIII. IMPACTS TO AMBIENT AIR QUALITY

A. Introduction

WMGF has performed comprehensive air quality modeling analyses for comparison to three types of standards or guidelines for its proposed power generation facility in Yuma County, Arizona. The WMGF is large enough to fall under the umbrella of the Federal PSD regulations. These regulations protect both Class I Wilderness Areas (designated Wilderness Areas and National Parks) and Class II Wilderness Areas. PSD air quality modeling typically involves both near-field (close to the source) and long-distance transport considerations to both Class I and Class II Wilderness Areas. Second, WMGF's emissions were simulated to predict concentrations of all pollutants (i.e. criteria pollutants) covered by the NAAQS and PSD increments. Third, the concentrations of several pollutants that do not have an air quality standard, but do have a Arizona Ambient Air Quality Guideline (AAAQG) were also simulated.

The purpose of the modeling analyses is to determine whether air quality impacts from WMGF's proposed criteria pollutant and hazardous air pollutant emissions will cause or contribute to a violation of any air quality standard, or worsen an existing air quality problem. WMGF has the flexibility to utilize either two GE 7FA combustion turbines or two SW 501F combustion turbines at the proposed facility. This section presents WMGF's worst-case modeling results from both types of turbines combined.

B. Overview of PSD Modeling

PSD ambient air quality analysis requirements are applicable to the WMGF project for NO_x, CO, SO_2, and PM_{10} pollutants. EPA's guidance for performing PSD air quality analyses is set forth in Chapter C of the October 1990 New Source Review Workshop Manual, as well as in 40 CFR Part 51, Appendix W. The modeling analysis is performed in two steps: a "facility-only" significant impact analysis, and if required, a cumulative impact or "multi-source" analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements.

The results of the significant impact modeling determine whether WMGF must perform a full impact analysis. If the ambient impacts are greater than the Significant Impact Levels (SILs, see Table 14), then the extent of the Significant Impact Area (SIA) of the proposed project is determined. The preliminary, "facility-only" impact analysis involves modeling impacts for comparison to both the Class II SILs and Significant Monitoring Concentration Levels as shown in Table 14. Pre-application air quality monitoring is necessary if the facility-only impacts exceed the Significant Monitoring Concentration Levels.

Table 14. Ambient Air Quality Standards

Pollutant	NO_2	CO ($\mu g/m^3$)		PM_{10} ($\mu g/m^3$)		SO_2 ($\mu g/m^3$)		
	Annual	1-hour	8-hour	24-hour	Annual	3-hour	24-	Annual
Class II Significant Impact Level	1	2,000	500	5	1	25	5	1
Significant Monitoring Conc. Level	14	---	575	10	---	---	13	---
PSD Class II Increment Level	25	---	---	30	17	512	91	20

NAAQS	100	40,000	10,000	150	50	1,300	365	80

The full impact analysis expands the "facility-only" significant impact analysis by considering emissions from both the proposed project as well as other sources in the SIA (and other sources outside the SIA that could cause significant impacts in the proposed source's SIA). The results from the full impact analysis are used to demonstrate compliance with NAAQS and PSD increments. The source inventory for the cumulative NAAQS analysis includes all nearby sources that have significant impacts within the proposed source SIL, while the source inventory for the cumulative PSD analysis is limited to increment-effecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date).

The full impact analysis is limited to receptor locations within the proposed project's SIA. The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations and the total concentrations are compared to the NAAQS. Conversely, the modeled air quality impacts for all increment-consuming sources are directly compared to the PSD increments to determine compliance (without consideration of ambient background concentrations).

C. Modeling Analysis Overview

1. Air Quality Models

The typical refined model used in air quality analyses is the Industrial Source Complex Short Term Model (ISCST3 Version 02035). The ISCST3 model was used to determine conservative impacts from a preliminary loads analysis (see Section VIII.C.4 below). In addition, the ISCPRIME (Version 99020) model was used by the applicant for the refined modeling analyses (i.e. NAAQS, PSD increment, AAAQG analysis, etc.) because of the importance of building downwash. The model has been approved for use in similar power generation projects in Arizona by ADEQ after consultation and approval from EPA Region IX.

ISCPRIME and ISCST3 are steady-state, multiple-source, Gaussian dispersion models. ISCPRIME and ISCST3 are used to estimate impacts at receptors located in simple terrain and complex terrain (within 50 kilometers (km) of a source) due to emissions from complicated sources. The models are capable of calculating downwind ground-level concentrations due to point, area, and volume sources and can accommodate a large number of sources and receptors. The ISCPRIME model has been specifically developed to predict the impacts from building downwash more accurately than ISCST3. For modeling Class I impacts greater than 50 km from WMGF, the applicant used the CALPUFF model. CALPUFF is a multi-layer, multi-species, non-steady state puff dispersion model that simulates the effects of time-and-space-varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF has recently been adopted into the Guideline on Air Quality Models (40 CFR 51, Appendix W) as a long-range transport model.

2. NAAQS Modeling Inventory

In addition to modeling the proposed source and adding background values, EPA requires that, at a minimum, all “nearby” sources be explicitly modeled as part of the full NAAQS analysis for PSD. The EPA modeling guideline (40 CFR 51, Appendix W) defines a “nearby” source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, "vicinity" is defined as the SIA for each pollutant. However, the location of such nearby sources could be anywhere within the significant impact area or an annular area extending 50 kilometers beyond the SIA.

For the full NAAQS modeling analyses, all permitted sources within WMGF's SIA must be explicitly modeled. However, for all PSD pollutants, it was determined that no permitted sources exist within any of WMGF's SIAs.

In addition, all permitted sources located outside the SIA and within the annular area extending 50 km from the SIA must also be included if they interact with the new source. Whether to include a potentially interacting source can be determined using the '20D' approach (also followed by Ohio EPA), also known as the North Carolina Protocol. The '20D' approach assumes a linear inverse proportional relationship between source emissions and impacts with distance. A '20D' facility-level screening approach is used to eliminate a majority of regional facilities from the PSD NAAQS modeling analysis that would not be expected to have a significant impact on analysis results. Under this approach, the applicant may exclude sources that have potential allowable emissions in TPY that are less than 20 times the distance ('20D') between the two sources in kilometers.

Those sources that are not eliminated using the '20D' approach should be modeled in the full NAAQS analysis. Two regional sources, the Arizona Public Service Yucca Power Plant and Yuma Cogeneration Associates, were included in WMGF's full NAAQS modeling analyses since they could not be eliminated using the '20D' approach.

3. *Increment Modeling Inventory*

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting an area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment.

According to PSD Guidelines, the increment inventory to be considered in the modeling analysis includes all increment-affecting sources located within the SIA of the proposed new source or modification. In addition, all increment-affecting sources located within 50 kilometers of the SIA should also be included in the inventory if they, either individually or collectively, affect the amount of PSD increment consumed. In general, the stationary sources of concern for the increment inventory are those stationary sources with actual emission changes occurring since a baseline date.

The proposed WMGF will affect increment. It was also determined that emissions changes from the segment of Interstate 8 (I-8) located within WMGF's SIA will affect increment. WMGF also included the impacts of the Arizona Public Service Yucca Power Plant and Yuma Cogeneration Associates in their increment analyses.

4. *Loads Analysis*

A detailed load-screening analysis was first conducted to determine which WMGF operating scenarios resulted in worst-case ambient impacts for each pollutant. A loads analysis is a preliminary modeling exercise in which combinations of ambient temperature and turbine loads are analyzed to determine which combination leads to the highest modeled impact.

As noted by the applicant in the PSD application, emissions from combustion turbines vary with ambient temperature. Additionally, ambient impacts from combustion turbines are also related to exhaust flow rates which are based on turbine loads. Typically, maximum short-term emissions of pollutants do not occur at peak loads. At intermediate load conditions, exhaust flow rates are lower than at peak loads. Such exhaust flow rates in combination with stable atmospheric conditions can result in poor pollutant dispersion.

For each pollutant and each averaging time, the applicant considered a matrix of ambient temperatures, relative humidity, duct firing on/off, and various combustion turbine loads. The applicant determined the combination of temperature and combustion turbine load that lead to the highest modeled impact for each pollutant for each averaging time. In addition, WMGF also considered worst-case startup and shutdown emissions scenarios for the combustion turbines in conjunction with the loads analysis.

For each pollutant, averaging time, and operational configuration (i.e. duct firing on/off), the modeling simulation which displayed the highest modeled impact from the preliminary loads analysis was incorporated into the SIA, significant monitoring concentration, NAAQS, PSD increment, and AAAQG modeling analyses.

5. *Modeled Emissions*

For each pollutant and each averaging time, WMGF's modeling analyses considered worst-case scenarios based on various emission rates (normal operations, start-up, shutdown, varying loads etc.) and modeled impacts from loads analyses. Table 15 indicates the criteria pollutant emissions considered in the NAAQS modeling analysis.

Table 15. Modeled Emission Rates

Modeling Input ID	Source	Emission Rate[1]							
		NO_2	CO		PM_{10}		SO_2		
		Annual	1-hour	8-hour	24-hour	Annual	3-hour	24-hour	Annual
CC01	CT/HRSG1[2,3]	5.22E+00	1.51E+02	7.90E+01	3.29E+00	4.15E+00	5.64E-01	6.73E-01	6.73E-01
CC02	CT/HRSG2[2,3]	5.22E+00	1.51E+02	7.90E+01	3.29E+00	4.15E+00	5.64E-01	6.73E-01	6.73E-01
0003	Auxiliary Boiler	7.12E-02	3.67E-01	3.67E-01	1.31E-02	8.50E-04	1.10E-02	9.00E-03	6.00E-03
0004	BS Generator 1	5.82E-02	5.06E+00	5.06E+00	2.79E-01	1.53E-02	1.56E-02	6.49E-03	3.55E-04
0005	BS Generator 2	5.82E-02	5.06E+00	5.06E+00	2.79E-01	1.53E-02	1.56E-02	6.49E-03	3.55E-04
0006	Fire Pump	2.15E-02	8.20E-02	8.20E-02	5.57E-04	1.53E-04	1.26E-02	1.05E-03	2.88E-04
0007	Cooling Tower Cell 1	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
0008	Cooling Tower Cell 2	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
0009	Cooling Tower Cell 3	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
0010	Cooling Tower Cell 4	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
0011	Cooling Tower Cell 5	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
0012	Cooling Tower Cell 6	N/A	N/A	N/A	1.37E-02	1.37E-02	N/A	N/A	N/A
AP01	APS - Yucca	3.46E+01	4.12E+00	4.12E+00	6.82E+00	6.82E+00	7.69E+01	7.69E+01	7.69E+01
AP02	APS - Yucca	2.71E+01	4.26E+00	4.26E+00	2.37E+00	2.37E+00	1.14E+01	1.14E+01	1.14E+01
AP03	APS - Yucca	2.71E+01	4.26E+00	4.26E+00	2.37E+00	2.37E+00	1.14E+01	1.14E+01	1.14E+01
AP04	APS - Yucca	8.06E+01	1.27E+01	1.27E+01	7.06E+00	7.06E+00	3.38E+01	3.38E+01	3.38E+01
AP05	APS - Yucca	8.06E+01	5.56E+00	5.56E+00	7.06E+00	7.06E+00	3.38E+01	3.38E+01	3.38E+01
AP06	APS - Yucca	2.71E+01	1.87E+00	1.87E+00	2.37E+00	2.37E+00	1.14E+01	1.14E+01	1.14E+01
AP07	APS - Yucca	2.53E+00	3.50E-01	3.50E-01	5.79E-01	5.79E-01	6.53E+00	6.53E+00	6.53E+00

Modeling Input ID	Source	Emission Rate							
		NO2	CO		PM10		SO2		
		Annual	1-hour	8-hour	24-hour	Annual	3-hour	24-hour	Annual
YC01	Yuma Cogeneration	1.05E+01	5.62E+00	5.62E+00	2.15E+00	2.15E+00	3.15E+00	3.15E+00	3.15E+00
YC02	Yuma Cogeneration	3.54E-01	1.07E-01	1.07E-01	3.46E-02	3.46E-02	1.44E-03	1.44E-03	1.44E-03
YC03	Yuma Cogeneration	5.82E-02	1.15E-01	1.15E-01	1.53E-02	1.53E-02	3.55E-04	3.55E-04	3.55E-04
RS01	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS02	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS03	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS04	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS05	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS06	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS07	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS08	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS09	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS10	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---
RS11	I-8 Road Segment	-1.42E-06	4.71E-05	4.71E-05	4.54E-08	4.54E-08	---	---	---

1. All emissions rates in grams per second (g/s), except road segments which are in grams per square meter per second (g/m^2-s)
2. NOx emissions rates were conservatively calculated for 2.5 ppmvd for modeling purposes and assuming 20 cold starts, 100 warm starts and 200 hot starts.
3. CO emissions rates were conservatively calculated for 5.0 ppmvd for modeling purposes and assuming 1 hot start for the 1- hour standard and 1 hot start and 1 cold start for the 8-hour standard.

The negative emission rates in Table 15 indicate that emissions have decreased since the baseline date for a particular pollutant. In addition, modeled emissions for sources RS01-RS11 and RS12-RS-23 differ due to different traffic counts between different mile markers on Interstate 8.

6. Source Release Parameters

Table 16 displays the source release parameters used in the modeling analysis for WMGF's combustion turbines.

Table 16. Source Parameters for Combustion Turbines

Pollutant	Averaging Period	Stack Ht. (m)	Stack Dia. (m)	Exit Temp. (deg K)	Exit Vel. (m/s)
NO_2	Annual	48.80	5.79	355	15.1
CO	1-hour	48.80	5.79	355	15.1
	8-hour	48.80	5.79	362	21.1
PM_{10}	24-hour	48.80	5.79	355	15.1
	Annual	48.80	5.79	357	20.8
SO_2	3-hour	48.80	5.79	362	21.1
	24-hour	48.80	5.79	357	20.8
	Annual	48.80	5.79	357	20.8

Note:	
A.	The values presented are for each CTG and HRSG.
B.	There will be two identical CTGs and HRSGs at the facility.

Table 17 displays the emissions and source release parameters used in the modeling analysis for all non-combustion turbine sources.

Table 17. Source Parameters for Non-CTG Sources

Modeling Input ID	Source	Stack Ht. (m)	Stack Dia. (m)	Exit Temp. (deg K)	Exit Vel. (m/s)
CC01	CTG/HRSG1	**See Previous Table**			
CC02	CTG/HRSG2				
0003	Auxiliary Boiler	18.30	1.52	366	3.1
0004	BS Generator 1	18.30	0.50	642	94.6
0005	BS Generator 2	18.30	0.50	642	94.6
0006	Fire Pump	4.60	0.13	796	59.6
0007	Cooling Tower Cell 1	N/A	N/A	N/A	N/A
0008	Cooling Tower Cell 2	N/A	N/A	N/A	N/A
0009	Cooling Tower Cell 3	N/A	N/A	N/A	N/A
0010	Cooling Tower Cell 4	N/A	N/A	N/A	N/A
0011	Cooling Tower Cell 5	N/A	N/A	N/A	N/A
0012	Cooling Tower Cell 6	N/A	N/A	N/A	N/A
AP01	APS - Yucca	44.70	3.20	422	12.3
AP02	APS - Yucca	9.80	3.05	747	14.5
AP03	APS - Yucca	10.00	3.05	747	14.5
AP04	APS - Yucca	9.70	3.05	791	55.1
AP05	APS - Yucca	9.80	3.05	789	53.4
AP06	APS - Yucca	9.80	3.05	765	16.5
AP07	APS - Yucca	10.50	0.91	558	18.9
YC01	Yuma Cogeneration Associates	25.90	3.20	444	25.6
YC02	Yuma Cogeneration Associates	9.10	0.61	505	10.7
YC03	Yuma Cogeneration Associates	18.30	0.50	642	94.6
RS01	I-8 Road Segment	2.00	926	100.00	-0.62
RS02	I-8 Road Segment	2.00	973	100.00	9.22
RS03	I-8 Road Segment	2.00	916	100.00	-1.14
RS04	I-8 Road Segment	2.00	996	100.00	-12.00
RS05	I-8 Road Segment	2.00	994	100.00	-64.20
RS06	I-8 Road Segment	2.00	738	100.00	-49.40

RS07	I-8 Road Segment	2.00	905	100.00	19.39
RS08	I-8 Road Segment	2.00	954	100.00	15.05
RS09	I-8 Road Segment	2.00	953	100.00	14.56
RS10	I-8 Road Segment	2.00	945	100.00	14.41
RS11	I-8 Road Segment	2.00	955	100.00	14.76
RS12	I-8 Road Segment	2.00	945	100.00	14.13
RS13	I-8 Road Segment	2.00	952	100.00	14.57
RS14	I-8 Road Segment	2.00	950	100.00	14.67
RS15	I-8 Road Segment	2.00	950	100.00	14.82
Modeling Input ID	**Source**	**Stack Ht. (m)**	**Stack Dia. (m)**	**Exit Temp. (deg K)**	**Exit Vel. (m/s)**
RS16	I-8 Road Segment	2.00	953	100.00	14.61
RS17	I-8 Road Segment	2.00	979	100.00	2.79
RS18	I-8 Road Segment	2.00	969	100.00	-11.90
RS19	I-8 Road Segment	2.00	950	100.00	-16.60
RS20	I-8 Road Segment	2.00	951	100.00	-16.60
RS21	I-8 Road Segment	2.00	947	100.00	-16.70
RS22	I-8 Road Segment	2.00	951	100.00	-16.90
RS23	I-8 Road Segment	2.00	943	100.00	-17.00

7. *Meteorological Data*

The PSD guidelines require that at least one year of on-site meteorological data, or alternatively, five years of National Weather Service (NWS) data be used in the analysis. Five years (1987-1991) of Phoenix Sky Harbor Airport surface meteorological data (Station Number 23183), with upper air data from the Tucson International Airport station (Station Number 23160), were utilized in the modeling analyses.

8. *Receptors*

According to the ADEQ Modeling Guidelines (June 1998), ADEQ recognizes that the ambient air begins at the process area boundary (PAB). Therefore, ADEQ does not recognize property boundaries or fence lines as the boundary between the ambient air and the source. For purposes of demonstrating compliance with the NAAQS, the PSD increment, and the AAAQGs, a receptor grid was created with sufficient density to determine the maximum model-predicted impact within the surrounding ambient air beyond WMGF's process area boundary. Receptor elevations were derived from the United States Geological Service (USGS) Digital Elevation Model (DEM) data.

The following receptor network was used in the WMGF modeling analyses:

- Receptors spaced at 25 meters between the PAB the facility fenceline;
- Receptors spaced at 100 meters from the facility fenceline to 2 kilometers;
- Receptors spaced at 250 meters from 2 kilometer to 5 kilometers; and
- Receptors spaced at 500 meters from 5 kilometers to 10 kilometers.

9. *Building Downwash and Good Engineering Practice (GEP)*

When calculating pollutant impacts, the ISCPRIME model has the capability to account for building downwash produced by airflow over and around structures. In order to do so, the model requires special input data known as direction-specific building dimensions for all stacks below the GEP stack height. All stacks included in the analysis are below GEP stack height.

A revised version of EPA's Building Profile Input Program (BPIP), BPIP-PRIME, was used to calculate the building downwash parameters for input to ISCPRIME. All the facility stacks are subject to downwash and building downwash effects were considered in all WMGF modeling analyses.

D. Modeling Analysis Results

1. *Significant Impact Area Modeling*

The applicant demonstrated that NO_2, CO, and PM_{10} emissions had predicted maximum concentrations greater than the SIL for any of the relevant averaging periods. Table 18 presents results from the significant impact analysis.

Table 18. Significance Analysis Results

Pollutant	Averaging Period	Maximum Project Impact (μg/m³)	Significant Impact Level (μg/m³)	SIA Exist?	Location UTM Easting (m) [1]	Location UTM Northing (m) [1]	Max. Distance to SIA (m)
NO_2	Annual	1.4	1	YES	756,649	3,617,517	5,537
CO	1-hour	1,331	2,000	YES [3]	757,382	3,612,765	284
	8-hour	300	500	YES [3]	752,132	3,616,015	259
PM_{10}	24-hour	8.9	5	YES	756,678	3,617,519	6,485
	Annual	1.7	1	YES	756,681	3,617,494	6,488
SO_2 [2]	3-hour	8.6	25	NO	756,681	3,617,544	N/A
	24-hour	1.0	5	NO	752,132	3,616,015	N/A
	Annual	0.2	1	NO	751,882	3,616,765	N/A

Note: Maximum impact from refined modeling and maximum distance to SIA determined from initial load screening modeling.

[1] UTM coordinates are in the NAD27 system; zone 11.

[2] SO_2 has no significant impacts in refined or load screening modeling.

[3] Based on ISCST3 load screening, a potentially small SIA for CO exists.

The concentration values listed under "maximum project impact" are from the refined ISCPRIME modeling.

The maximum distance of the significant impact area for NO_2 is approximately 5.5 kilometers from the facility. The maximum distance of the significant impact area for PM_{10} (for the annual averaging period) is approximately 6.5 kilometers from the facility. Based on the load screening analysis using ISCST3, it was determined that there was, potentially, a small SIA for CO. Therefore, a full impact analysis was conducted for these pollutants. Because modeled ambient concentrations were lower than the SILs for SO_2, no additional modeling was required for SO_2.

2. *NAAQS and Class II PSD Increment Analyses*

The full impact analysis expanded the significant impact analysis by considering emissions from both the proposed project as well as other sources in the SIA. Modeling was performed for criteria pollutants to determine if the proposed source would exceed the NAAQS or PSD increments.

For NO_2, CO, and PM_{10}, both the WMGF and regional sources were included in a full NAAQS analysis. For SO_2, the NAAQS modeling analyses only included the WMGF facility since the results in Table 18 indicated that the WMGF would not have significant impacts on air quality. The NAAQS modeling analysis is based on concurrent operations of equipment listed previously in Table 17. Results of the NAAQS analysis are presented in Table 19.

Table 19. NAAQS Modeling Analysis Results

Pollutant	Averaging Period	Concentration (μg/m³)			NAAQS (μg/m³)	% of NAAQS
		Modeled	Background	Total		
NO_2	Annual	4	4	8	100	8
CO	1-hour	1,331	582	1913	40,000	5
	8-hour	300	582	882	10,000	9
PM_{10}	24-hour	9	114	123	150	82
	Annual	2	39	41	50	82
SO_2	3-hour	82	246	328	1,300	25
	24-hour	19	45	64	365	18
	Annual	2	6	8	80	11

The highest predicted criteria pollutant impacts, without considering background concentrations, from WMGF's proposed facility are from SO_2 and PM_{10}. Without considering background concentrations, maximum predicted annual impacts of SO_2 and PM_{10} are approximately 6% of the NAAQS value. When considering both modeled concentrations and added background concentrations, the highest predicted criteria pollutant impacts from the proposed WMGF are from PM_{10} (82% of NAAQS value - almost all contributable to background concentrations). Based on the modeling analysis results, WMGF has demonstrated compliance with the NAAQS standards for its proposed power generation facility.

Results of the PSD increment analysis for Class II wilderness areas are presented in Table 20.

Table 20. PSD Class II Increment Analysis Results

Pollutant	Averaging Period	Maximum Class II Impact (μg/m³)	Location UTM (m) [1]	Location UTM (m) [1]	Class II Increment Level (μg/m³)	% of Class II Increment
NO_2	Annual	0.01	766,382	3,625,765	25	0.03
CO	1-hour	7,330	753,382	3,617,765	----	---
	8-hour	2,698	754,482	3,617,465	----	---
PM_{10}	24-hour	9	756,678	3,617,519	30	30
	Annual	2	751,632	3,617,015	17	11
SO_2	3-hour	9	756,681	3,617,544	512	2
	24-hour	1	752,132	3,616,015	91	1
	Annual	0.2	751,882	3,616,765	20	1

[1] UTM coordinates are in the NAD27

The maximum impact for the 24-hour PM_{10} Class II increment is 9 micrograms per cubic meter (µg/m^3). The maximum impact is approximately 30% of the PSD Class II 24-hour increment of 30 µg/m^3. Based on the modeling analysis results, WMGF has demonstrated compliance with the Class II PSD increments for its proposed power generation facility.

3. AAAQG Analysis

Modeling was performed to determine if the source would exceed the AAAQGs for air toxics of concern. This modeling used the same dispersion model (ISCPRIME), meteorological data, building downwash, and basic model parameters and assumptions used in the criteria pollutant modeling. Emissions of 12 AAAQG pollutants from the proposed WMGF were evaluated. The results of the AAAQG analysis are presented in Table 21.

Table 21. AAAQG Modeling Analysis Results

Pollutant	Averaging Period	Max. Modeled Conc. (µg/m^3)	AAAQG (µg/m^3)	% Of AAAQG
1,3-Butadiene	1-hour	1.70E-01	7.20E+00	2
	24-hour	1.23E-02	1.90E+00	1
	Annual	1.21E-04	6.70E-02	0.2
Acetaldehyde	1-hour	7.28E-01	2.30E+03	0.03
	24-hour	5.38E-02	1.40E+03	0.004
	Annual	3.80E-03	5.00E-01	1
Acrolein	1-hour	6.74E-01	6.70E+00	10
	24-hour	4.90E-02	2.00E+00	2
	Annual	---	---	---
Ammonia	1-hour	---	---	---
	24-hour	6.29E+00	1.40E+02	4
	Annual	---	---	---
Benzene	1-hour	4.18E-01	6.30E+02	0.1
	24-hour	2.99E-02	5.10E+01	0.1
	Annual	1.26E-03	1.40E-01	0.9
Ethylbenzene	1-hour	6.93E-02	4.50E+03	0.002
	24-hour	1.20E-02	3.50E+03	0.0003
	Annual	---	---	---
Formaldehyde	1-hour	5.26E+00	2.00E+01	26
	24-hour	5.07E-01	1.20E+01	4
	Annual	6.53E-02	8.00E-02	82
Naphthalene	1-hour	2.61E-02	6.30E+02	0.004
	24-hour	1.89E-03	4.00E+02	0.0005
	Annual	---	---	---
PAH (as benzo(a)pyrene)	1-hour	3.62E-02	7.90E-01	5

	24-hour	2.72E-03	2.10E-01	1
	Annual	2.08E-04	5.70E-04	36
Propylene Oxide	1-hour	6.16E-02	1.50E+03	0.004
	24-hour	1.07E-02	4.00E+02	0.003
	Annual	2.53E-03	2.00E+00	0.1
Toluene	1-hour	3.21E-01	4.70E+03	0.01
	24-hour	5.23E-02	3.00E+03	0.002
	Annual	---	---	---
Xylene	1-hour	1.50E-01	5.50E+03	0.003
	24-hour	2.50E-02	3.50E+03	0.001
	Annual	---	---	---

The modeled AAAQG concentrations listed in Table 21 are the maximum predicted impacts from the proposed WMGF at any location at or beyond WMGF's process area boundary. The modeling demonstrates that maximum predicted concentrations of all air toxics are less than the AAAQG values. The maximum annual impact is for formaldehyde, with impacts at 82% of the AAAQG. The maximum short term impact is for the 1-hour formaldehyde concentration, at 26% of the AAAQG. Based on the AAAQG modeling analysis results, WMGF has demonstrated compliance with the AAAQG guidelines for its proposed facility.

D. Additional Impacts Analysis

A.A.C. R18-2-407.I requires that WMGF's PSD permit application include an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the new source and general commercial, residential, industrial, and other growth associated with the new source.

1. Growth Analysis

The applicant estimates that approximately 30 permanent new positions will be needed for operation of the new facility. Therefore, the potential air quality impacts from additional industrial, commercial, and residential growth from this facility will be limited.

Increases in air emissions from this population influx are primarily a result of the increase in vehicle exhaust from the limited increase in traffic flow. The existing traffic flow on Interstate 8 (I-8) will not be significantly affected by this change. Therefore, the applicant estimates that no significant growth-related air quality impacts will occur. The Department concurs.

2. Soils and Vegetation Impacts Analysis

The most prominent community type represented in the project area is the Sonoran creosote bush-scrub. The dominant plant is the creosote bush (*Larrea tridentata*) associated with white bursage (*Ambrosia dumosa*) and big galleta grass (*Hilaria jamesii*). No sensitive plants were found in the project or surrounding area during WMFG's site survey. Areas of desert pavement are located throughout the project site. These sites are generally devoid of perennial species, with some scattered areas of annual forbs and grasses. The soil types are sandy and sandy loam. Some agricultural areas have been developed in this area near the plant site.

Deposition of particulates from the cooling towers and the CTG and HRSG stacks was analyzed for impacts to crops. Cooling tower drift refers to the mist and droplets that are emitted from the cooling tower into the atmosphere. Heavier droplets can fall onto soil and vegetation.

A multi-cell mechanical cooling tower located near the center of the site is proposed at WMGF. Source water is recycled in the towers until it reaches a TDS content of approximately 10,000 ppm. The mist would contain concentrations of calcium, magnesium, and other common salts.

Cooling tower drift is minimized by a passive system of drift eliminators, which limits the amount of drift that escapes the tower to 0.0005 percent of the circulating water. The total drift rate was calculated using this drift rate with an estimate of the recirculation rate for cooling water. Most of the airborne drift, consisting of water droplets with the same solids content as in the circulating water, will evaporate quickly in the high local temperature, leaving dry particulate.

There are relatively few studies of adverse effects of salt deposition on commercial plants. Pahwa and Shipley (1979) exposed corn, tobacco, and soybean crops to simulated drift from cooling towers, using salt water (20,000 to 25,000 ppm TDS). Symptoms of stress from salt on the most sensitive crops were "barely perceptible" at a deposition rate of 2.98 grams per square meter (g/m^2)-year (Pawha and Shipley, 1979).

The Seasonal Annual Cooling Tower Impact model was used to assess deposition impacts from the cooling tower drift emissions. This model requires meteorological data in the CD144 format; therefore, 3 years of CD144 data collected in Blythe, California, were used. These data were assumed to be representative of the Yuma area.

Using the maximum predicted annual average drift rate of 54 g/s and an estimated water quality of 10,000 ppm TDS, the estimated maximum annual predicted deposition for PM_{10} would be 5.0 g/m^2 per year. This maximum impact is predicted to occur 200 meters from the cooling tower. At 300 meters from the cooling tower, the maximum deposition is reduced to 1.0 g/m^2 per year, and to 0.8 g/m^2 per year at 400 meters. Thus, deposition of cooling tower drift and other particulate emissions from the facility are not anticipated to cause adverse effects to vegetation or crops.

Regarding gaseous air pollutants, no emissions are predicted to result in concentrations that exceed the NAAQS for CO, NO_2, or SO_2. Since there are low ambient impacts from the proposed WMGF and there are no sensitive plants on or near the project site, it is concluded that the proposed WMGF will pose no adverse impacts to soils or vegetation from deposition of particulate or gaseous pollutants. The Department concurs.

3. *Visibility Impacts Analysis*

R18-2-410 requires that the PSD permit application include an analysis of the impacts that emissions from proposed facility will have on visibility. The visibility analysis was conducted for nearby special Class II Wilderness Areas, including Bureau of Land Management (BLM) Wilderness Areas, as requested by the Federal Land Manager (FLM). The BLM has concluded that the magnitude and frequency of impacts, combined with the conservative nature of the analysis and the low probability of occurence of the impacts, will not adversely affect visibility at the Muggins Mountain Wilderness area.

4. *Class I Wilderness Area Impacts Analysis*

In addition to visibility modeling in BLM Class II Wilderness Areas, WMGF modeled visibility impacts at the Joshua Tree National Park Class I Wilderness Area. It was determined that the maximum change in extinction from the proposed WMGF project will be approximately 4.35% at the Class I Wilderness Area. The NPS has concluded that the magnitude and frequency of impacts, combined with the conservative nature of the analysis and the low probability of occurence of the impacts, will not adversely affect visibility at the Joshua Tree National Park Class I Wilderness Area.

WMGF also modeled impacts at the Joshua Tree National Park Class I Wilderness Area for comparison to Class I PSD increments. Class I PSD increment results are presented in Table 22.

Table 22. PSD Class I Increment Analysis Results

Pollutant	Averaging Period	Maximum Class I Impact (μg/m³)	Location UTM Easting (m) [1]	Location UTM Northing (m) [1]	Class I Increment Level (μg/m³)	% of Class I Increment
Joshua Tree National						
NO_2	Annual	0.01	587,191	3,629,364	2.5	0.3
CO	1-hour	---	---	---	---	---
	8-hour	---	---	---	---	---
PM_{10}	24-hour	0.1	587,191	3,629,364	8	1.6
	Annual	0.01	587,010	3,626,402	4	0.4
SO_2	3-hour	0.05	587,191	3,629,364	25	0.2
	24-hour	0.01	587,191	3,629,364	5	0.2
	Annual	0.001	587,010	3,626,402	2	0.1

[1] UTM coordinates are in the NAD27

5. *Conclusions*

The applicant has adequately demonstrated compliance with the NAAQS and PSD increments. In addition, WMGF has demonstrated compliance with the AAAQG guidelines for its proposed facility. The FLM has concluded that the magnitude and frequency of impacts, combined with the conservative nature of the analysis and the low probability of occurence of the impacts, will not adversely affect visibility in the Class I and II wilderness areas.

IX. INSIGNIFICANT ACTIVITIES

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PURSUANT TO A.A.C. R18-2-101.57
1	Building HVAC Exaust Vents
2	Turbine Compartment Ventilation Exhaust Vents
3	Sanitary Sewer Vents
4	Compressor Air Systems
5	Turbine Lube Oil Vapor Extractors and Lube Oil Mist Eliminator Vents
6	Steam Drum Safety Relief Valve Vents
7	Building Air Conditioning Units
8	Emergency Diesel Fire Pump Fuel Storage Tanks
9	Sulfuric Acid Storage Tank Vents
10	Various Steam Release Vents
11	Welding Equipment
12	Lab Hood Vents
13	Water Wash System Storage Tank Vents
14	Neutralization Basin
15	Sodium Hypochlorite Storage Tanks
16	Hydrazine Storage TanksVents
17	Fuel Purge Vents
18	Oil/Water Separator Waste Oil Collection Tanks
19	Condenser Vacuum Pump Vents
20	Sodium Hydroxide Tank

X. LIST OF ABBREVIATIONS

AAAQG .... Arizona Ambient Air Quality Guideline
A.A.C. .... Arizona Administrative Code
ADEQ .... Arizona Department of Environmental Quality
AQRV .... Air Quality Related Value
BACT .... Best Available Control Technology
BLM .... Bureau of Land Management
BPIP .... Building Profile Input Program
CAM .... Continuous Assurance Monitoring
CEMS .... Continuous Emission Monitoring System
CFR .... Code of Federal Regulations
CMS .... Continuous Monitoring Systems
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
CTG .... Combustion Turbine Generator
deg K .... Degrees Kelvin
DEM .... Digital Elevation Model
DLN .... Dry Low-NO_x
dscf .... Dry Standard Cubic Foot
EPA .... Environmental Protection Agency
ESP .... Electro Static Precipitator
^oF .... Degrees Fahrenheit
FLM .... Federal Land Manager
GE .... General Electric
GEP .... Good Engineering Practice
g/bhp-hr .... Grams per Brake Horsepower Hour
g/s .... Grams per Second
g/m^2 .... Grams per Square Meter
g/m^2-s .... Grams per Square Meter per Second
gr/dscf .... Grains per Dry Standard Cubic Foot
hr .... Hours
H_2 .... Hydrogen
H_2O .... Water
HRSG .... Heat Recovery Steam Generator
hp .... Horsepower
ISC3 .... Industrial Source Complex Version 3
ISCST3 .... Industrial Source Complex Short Term Model Version 02035
km .... Kilometers
lb .... Pounds
lb/hr .... Pound per Hour
lb/MMBtu .... Pounds per Million British Thermal Units per Hour
lb/MW-hr .... Pound per Megawatt Hour
m .... Meters
m/s .... Meters per Second
$\mu g/m^3$ .... Microgram per Cubic Meter
mg/m^3 .... Milligram per Cubic Meter
MMBtu .... Million British Thermal Units
MMBtu/hr .... Million British Thermal Units per Hour
MW .... Megawatt
N/A .... Not Available
NA .... Not Applicable
NAAQS .... National Ambient Air Quality Standard
N_2 .... Nitrogen

NH_3	Ammonia
NO	Nitrogen Oxide
NO_x	Nitrogen Oxides
NO_2	Nitrogen Dioxide
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
O_2	Oxygen
O_3	Ozone
PAB	Process Area Boundary
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter Nominally less than 10 Micrometers
ppm	Parts per Million
ppmvd	Parts per Million by Dry Volume
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gage
PTE	Potential-to-Emit
RATA	Relative Accuracy Test Audit
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SIA	Significant Impact Area
SIL	Significant Impact Level
SNCR	Selective Non-Catalytic Reduction
SO_x	Sulfur Oxides
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Turbine Generator
SW	Siemens Westinghouse
TDS	Total Dissolved Solids
TPY	Ton per Year
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Services
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound
WMGF	Wellton Mohawk Generation Facility
yr	Year